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STRATEGIES FOR COMMERCIALIZING CUSTOMER THERMAL-ENERGY STORAGE

by

Samuel H. Nelson

ARGONNE NATIONAL LABORATORY

ANL
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ENERGY AND ENVIRONMENTAL SYSTEMS DIVISION

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Samuel H. Nelson

Energy and Environmental Systems Division

December 1976

*Work supported by the Chemical and Thermal Branch, Division of Energy Storage Systems, Office of the Assistant Administrator for Conservation, U. S. Energy Research and Development Administration.

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ABSTRACT

This report presents strategies for commercializing customer thermal storage. Four storage techniques are evaluated: space heating, air conditioning, hot-water heating, and interruptible hot-water heating. The storage systems involved store off-peak electric energy for thermal applications during peak load hours. Analyses of both storage techniques and principal parties affected by storage indicate four barriers: the absence of (1) commercially available air conditioning storage devices, (2) appropriate rates, (3) information on both rates and devices, and (4) widespread utility support. Development of appropriate rates is the key to commercialization. The criteria used to evaluate rate types are: maximum combined utility and customer benefits, ease of commercialization, and practical feasibility. Four rate types -- demand charges, time-of-use rates, and two forms of load management rates (a monthly credit and an off-peak discount) -- plus the possibility of utility ownership are considered. The best rate types for each storage option are: for hot-water heating, a monthly credit for allowing utility interruptions or an off-peak price discount for storage; for space heating, an off-peak discount contingent upon meeting utility requirements; and for air conditioning, an off-peak discount plus monthly credit.

1 *INTRODUCTION AND SUMMARY*

1.1 SCOPE AND OBJECTIVES

This report presents strategies for commercializing theremal energy storage (TES) in buildings. The principal criterion used is maximizing social benefit while also considering near-term benefits. The storage systems involved would be installed on the customer's premises to store off-peak electric energy for thermal applications during peak load hours. The economic rationale for TES is that the cost of electric power is considerably lower during off-peak hours than during on-peak hours.

The principal objectives of the study are to:

1. Determine the barriers to commercializing TES.
2. Devise strategies to overcome the barriers to commercializing TES.
3. Recommend, from a social-welfare standpoint, the best strategies to commercialize TES.

1.2 *SUMMARY OF STUDY FINDINGS*

1.2.1 *Determination of Barriers*

There are four requisites to successful commercialization:

1. Developing a viable, cost-effective technology,
2. Devising a means to transfer economic benefits to ultimate consumers,
3. Providing relevant information to all concerned parties, and
4. Overcoming existing institutional barriers.

Thermal energy storage involves four separate, but related, technologies, three of which -- storage hot-water heating, building heating, and air conditioning -- store energy overnight (off-peak) for use during the day, while the fourth, interruptible hot-water heaters, involves interrupting hot-water service for up to four hours. Either a radio or ripple-control (ripple control sends coded messages through power lines) mechanism can be used to interrupt and resume the supply of electricity. Both Detroit Edison and Buckeye Power have successfully used radio control to interrupt customers with conventional-size hot-water heaters. Storage hot-water heaters are larger, better insulated, and more expensive than conventional water heaters, and have the capacity to store sufficient hot water overnight to carry through the day. Storage space-heating has been in use in Europe for some 15 years. German units are currently available in the United States. These units store heat in magnesite brick. Central-storage space-heat involves blowing air past the hot bricks and ducting it into the rooms. For dispersed units, the bricks are enclosed in boxes that heat by a combination of radiation and convection. The convection is provided by individual unit fans. There are no commercial air conditioning systems at present. Work is underway using ice as the storage medium, but nothing is as yet on the market. Clearly, then, only for storage air conditioning is the status of the technology a barrier.

Successful commercialization entails satisfying the needs of the principal participants. For TES these parties are:

1. The electric utilities, which supply electricity to be thermally stored,
2. The public utility commissions, which are responsible for ensuring that electricity is reasonably priced and adequately supplied,
3. The TES vendors, who provide storage and/or storage-enhancing devices,
4. The ultimate customer, who must purchase either the service provided by TES devices or the devices themselves,
5. Real-estate developers, who are responsible for installation of storage systems in new buildings, and
6. Financial institutions, which are called upon to finance TES installations.

Meeting needs involves knowing both participant goals and the way in which TES relates to these goals.

1. The profits of privately owned public utilities are constrained by regulation. Although making satisfactory profits is their primary goal, both organizational requirements and the professional integrity of management are important subsidiary goals. Thus utilities strive to achieve provision of the best possible level of service consistent with sufficient profits. Publicly owned utilities and electric cooperatives have similar goals, but with even less emphasis on profits.

In a typical utility a large portion of generating equipment is seldom used, as shown in Fig. 1.1. Furthermore, even on peak-demand days, there is a considerable period during which demand is significantly below the peak, as shown in Fig. 1.2. Supplying more power at these off-peak times, instead of on-peak, is considerably less costly, since no new capacity is required. The utility therefore can offer a considerably reduced rate for off-peak power.

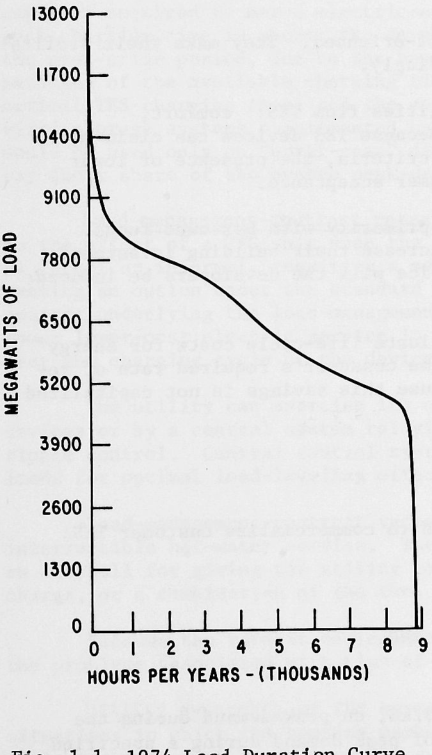

Fig. 1.1 1974 Load Duration Curve for a Large Midwestern Utility

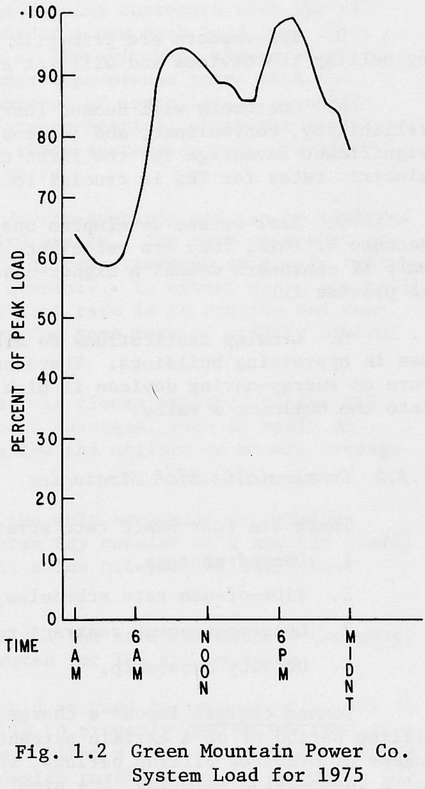

Fig. 1.2 Green Mountain Power Co. System Load for 1975 Peak Day, Dec. 19, 1975

Likewise, by interrupting customers at peak time, significant capacity cost savings are attainable. TES therefore appeals to both the profit and non-profit goals of utilities. By reducing capacity costs to supply the same amount of energy there is potential for profit improvement. The provision of a new service at low cost is an activity that should appeal to the professional integrity of utility personnel. Introducing TES devices will provide the exciting, socially useful, challenge to attract the high-caliber professionals necessary to maintain a viable organization.

Unfortunately, there is very little utility experience with TES. Thus, information must be provided on the devices, their advantages for utilities, and the appropriate rate structures for their introduction.

2. Public Utility Commissions (PUCs) aim to resolve the complaints of their split clientele: the general public and the utility. Indices of success are fewer rate filings, fewer interventions, fewer antagonistic political statements, etc. Because TES allows utilities to increase profits while at the same time offering consumers a new, low cost service, TES should be viewed favorably by the PUCs.

3. TES vendors are primarily profit-oriented. They make their profits by selling TES devices and will act accordingly.

4. Customers will demand four qualities from TES: comfort, reliability, convenience, and low cost. Because TES devices can claim no significant advantage for the first three criteria, the presence of lower electric rates for TES is crucial to consumer acceptance.

5. Real-estate developers operate primarily with borrowed funds. Because of this, they are reluctant to increase their building investment. Only if consumers demand a higher-cost device will the developers be induced to provide it.

6. Lending institutions do not evaluate life-cycle costs for energy use in appraising buildings. Therefore, the consumer's required rate of return on energy-saving devices is high because this savings is not capitalized into the building's value.

1.2.2 Commercialization Strategies

There are four basic rate strategies to commercialize customer TES:

1. Demand charges,
2. Time-of-use rate schedules,
3. Load-management contract rates, and
4. Utility ownership.

Demand charges impose a charge, in \$/kW, on peak demand during the billing period or on a certain percentage of peak demand during a specified number of previous billing periods, whichever is greater. These rates involve inexpensive metering, are simple and easy to understand, and are currently used in commercial and industrial markets. One disadvantage, however, is that, because of high power requirements of certain residential appliances, demand charges are unpopular with residential customers. Another disadvantage is that demand charges do not fully incorporate the time element of cost. Thus, while rewarding customers with level diurnal loads, they penalize customers with nighttime peaks, even though supplying the latter may cost less. This problem can be surmounted by time-varying the demand charge, a form of time-of-use rates.

Time-of-use rate schedules involve a relatively high charge on consumption during peak-load periods and much lower rates during off-peak periods. The peak-period rate covers both capital and operating costs; the off-peak rate, only the operating costs of base-load units. In practice, time-of-use tariffs usually involve two or, at most, three daily pricing periods and two or three seasonal periods.

Providing a lower rate off-peak is an incentive to install TES devices. However, because of the level of aggregation inherent in the design of time-of-use rates, they are poorly matched to the operating characteristics of TES devices. The most important neglected effects are: the extra distribution capacity required to serve electric-storage-heating customers when the off-peak charging time is short; the development of a new peak load just after the peak-price period, due to the bunching of TES switch-on times; poor matching of the available charging time under time-of-use rates with the optimal TES charging time; and the encouragement of installation of undersized storage systems supplemented by resistance-heating, where the resistors would be used only on "worst-case" days -- these systems do not, therefore, pay their share of the system peak-demand costs.

Load-management-contract rates are device-specific and can be tailored to the effect of a TES unit upon the utility system. The rate contracts can be formal or informal, requiring a separate signed agreement or simply representing an option under the standard rate schedule. In either case, the basic concept underlying the load-management-contract rate is to provide the customer lower-cost electric service in return for some form of utility control over the charging cycle of the device.

The utility can exercise its control via clocks attached to the TES devices or by a central system relaying coded messages, such as radio or ripple control. Central control systems allow the utility to manage storage loads for optimal load-leveling effect.

Load-management-contract rates are the only mechanism to provide interruptible hot-water service. These rates may consist of a monthly credit on the bill for giving the utility control, a low off-peak kilowatt-hour charge, or a combination of the two.

Because the rate is device-specific and the utility controls charging, the problems associated with time-of-use rates for TES are overcome.

Utility ownership of TES systems could be used to commercialize TES in situations in which the housing market fails to properly capitalize the life-cycle customer-cost savings of TES systems. Given a four-year expected house occupancy and a 10% interest rate, a TES device purchaser would require a 32%

return on investment in situations in which the housing market valued TES and conventional systems equally.

However, utility ownership would induce customers to install devices, especially air conditioning, where they would not do so if they had to provide financing. Since utility ownership involves a subsidy, the costs associated with induced storage customers could outweigh the benefits resulting from shifting customers from conventional to storage systems. As this also entails increased energy use, utility ownership is clearly not a viable alternative.

1.2.3 Recommendations

The preceding section indicates that the variables and issues affecting the choice of rate strategies to commercialize customer TES are numerous and complex. Indeed each TES type has a different preferred strategy when the criteria of maximum social benefit and practical feasibility are applied.

Electric storage space heating. The recommended strategy is the offering of load-management-contract rates. In service areas in which electric storage heating is cost-effective, the standard space-heating rate is usually high enough (≃3.0¢/kWh) to allow a rate discount adequate to provide the customer with the required payback. When TES market penetration is expected to be large, the utility should install a real-time control system to maximize the load-leveling benefits.

Storage air conditioning. Because the rate discount required to commercialize is so large (see Table 1.1), utility ownership appears to be the only feasible strategy. Certainly in cool climates such as Service Area C, it appears difficult to devise any politically acceptable combination of monthly credits and energy price discounts that would provide the customer an adequate return on investment. It may, however, be possible to design an acceptable load-management-contract rate in warmer climates where considerably more energy is used for air conditioning.

Hot-water heaters. Although storage water heaters offer greater net benefits than interruptible service (see Table 1.1), they are more difficult to commercialize. These systems require the customer to invest in a larger tank, whereas interruptible service requires only the addition of a control device to a standard tank. Because of the considerably greater near-term potential, the preferred strategy is for the utility to offer a monthly credit for the right to interrupt service.

The success of TES is also dependent upon providing information of its benefits first to utilities to stimulate initiation of programs and then to consumers. Informing the latter is primarily a task for utility marketing divisions; utilitites should be informed via Electric Power Research Institute findings, other utilities, and government-funded efforts. Although utility action, particularly the implementation of appropriate rates, is the key to commercializing TES, four promotional measures can be taken by government agencies (either directly or via agents) concerned with energy savings: (1) provide expertise on the proper rates for thermal-storage devices, (2) work with utilities to develop their support of TES, (3) conduct research and development on storage cooling, and (4) promote the introduction of the life-cycle cost concept into the housing market.

Table 1.1 Utility Savings Versus Customer Payback Requirements[a]

Table 1.1 Utility Savings Versus Customer Payback Requirements[a]

Service Area[b]	Application	Storage Discharge Period (hrs)	Annual Consumption (kWh)	Utility Savings (¢/kWh)	TES Increm'tl Cost ($)	Payback Req'd to Commercialize[c] 3-year $/yr	3-year ¢/kWh	5-year $/yr	5-year ¢/kWh
A	Hot Water	4	5,840	1.0	105	35	0.6	21	0.4
A	Hot Water	16	5,840	3.3	320	107	1.8	64	1.1
A	Space Htg.	8	28,000	5.1	2,840	946	3.4	568	2.0
B	Hot Water	4	5,840	2.0	105	35	0.6	21	0.4
B	Hot Water	16	5,840	3.3	320	107	1.8	64	1.1
B	Space Htg.	8	27,600	2.9	2,760	945	3.4	552	2.0
C	Hot Water	4	5,840	0.8	105	35	0.6	21	0.4
C	Hot Water	16	5,840	2.2	320	107	1.8	64	1.1
C	Air Cond.	8	2,500	14.6	1,095	365	14.6	219	8.8
D	Hot Water	4	5,840	1.9	105	35	0.6	21	0.4
D	Hot Water	16	5,840	3.1	320	107	1.8	64	1.1
D	Air Cond.	8	6,500	14.6	1,325	442	6.9	265	4.1

[a]From Asbury et al., *Assessment of Energy Storage Technologies and Systems, Phase I: Electric Storage Heating, Storage Air Conditioning, Storage Hot Water Heaters*, Argonne National Laboratory, ANL/ES-54 (Oct. 1976).

[b]Service areas A and B are winter peaking; C and D are summer peaking. Thus, there are no net savings for air conditioning TES for service areas A and B or for space heating TES for C and D.

[c]Simple payback; does not include cost of capital.

2 BACKGROUND AND OBJECTIVES

2.1 THE BASIC CONCEPT OF CUSTOMER TES AND THE COMMERCIALIZATION PROCESS

Thermal energy storage (TES) from electricity involves installing systems on the customer's premises, for the purpose of thermally storing off-peak electric energy, to be used in thermal applications during peak load hours. Figure 2.1 illustrates this idea.

By displacing energy consumption from the electric utility's peak-load period to the off-peak period, TES produces the following economic benefits:

1. A reduction in the rate of growth of the utility's peak loads with a corresponding reduction in generation, transmission, and distribution capacity from what would otherwise be required.
2. Improved daily load factors, allowing the substitution of base-load generating plant and fuels for peak- and intermediate-load generating plant and fuels.
3. A reduction in the cost of electricity supply, thereby enabling a greater market penetration for electricity than could otherwise occur.

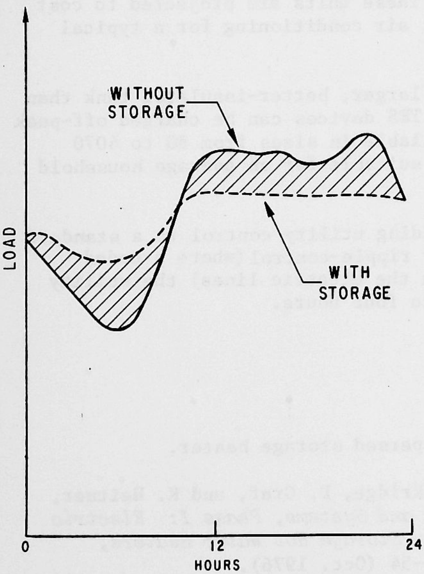

Fig. 2.1 Effect of Customer-Owned Storage on Electric-Utility Daily Load Curve

Against these benefits, occurring mostly on the utility side of the electric meter, must be weighed the additional capital costs on the customer side of the meter. Only when the benefits exceed the extra customer costs is it desirable to commercialize TES systems.

There are four requisites to successful commercialization of a product: (1) development of a viable, cost-effective technology, (2) devising a means to transfer economic benefits to ultimate consumers, (3) provision of relevant information to all concerned parties, and (4) overcoming any existing institutional barriers. Therefore, the commercialization process consists of first developing the technology, then devising an attractive price-performance package for the customer, and finally informing the customer of the device's potential benefits while simultaneously overcoming any institutional barriers, such as legal requirements, that arise. Devising commercialization strategies, accordingly, requires awareness of (1) the current status of the technology, in this case, TES; (2) the goals of the principal parties involved; (3) appropriate pricing mechanisms; and (4) the relevant institutions.

2.2 *TES TECHNIQUES*

TES involves four separate, but related technologies. Three of these -- space heating, air conditioning, and hot-water heating -- store energy overnight (off-peak) for use during the day. The fourth, interruptible hot-water heaters, involves interrupting hot-water service at peak times.

Space-heating TES devices are well developed, having been in use in Europe for 15 years. They are currently available in both room-size and central-heat models.* These units are designed to be charged during off-peak hours and discharged during the rest of the day. They meet American requirements for comfort, convenience, and reliability. At present, customer cost is about $2500 more than a conventional system for an average dwelling. Because of reduced freight costs and absence of tariff, this cost should be considerably reduced when units are made domestically.

Air conditioning TES devices are still in the developmental stage. Several companies are developing devices that will store coolth for peak time discharge. One promising technique, being developed by A.O. Smith, is to store ice in modified hot-water tanks. The ice is melted as cooling is needed and the cold air vented to the building. These units are projected to cost about $1000 more than conventional central air conditioning for a typical home.

Hot-water TES devices are simply a larger, better-insulated tank than those in conventional service. Hot-water TES devices can be charged off-peak for daytime use. These are currently available in sizes from 80 to 4070 gallons. The incremental cost for a tank suitable for an average household is $215.**

Interruptible hot water involves adding utility control to a standard home-hot-water system. By either radio or ripple-control (where a coded message is delivered to a receiver through the electric lines) the utility switches off the electric current for up to four hours.

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*See Appendix I for a description of a dispersed storage heater.

**See J. Asbury, R. Giese, S. Nelson, L. Akridge, P. Graf, and K. Heitner, *Assessment of Energy Storage Technologies and Systems, Phase I: Electric Storage Heating, Storage Air Conditioning, Storage Hot Water Heaters*, Argonne National Laboratory Report ANL/ES-54 (Oct. 1976).

2.3 REPORT OBJECTIVES AND OVERVIEW

The principal objectives of this study are to:

1. Determine the barriers to commercializing customer TES.

2. Devise strategies to overcome the barriers to commercializing TES.

3. Recommend the best strategies to commercialize TES.

Chapter 3 describes the characteristics of the principal actors in the TES drama and in so doing elucidates the remaining barriers to commercializing TES. Chapters 4 and 5 examine the critical problem, electric utility rates. Chapter 4 includes the theory for proper electric pricing, alternative modes to price TES, and a review of current pricing experiments with particular emphasis on those involving TES. Chapter 5 defines the best rate structures for commercializing TES, the prime criterion being social welfare, although consideration is given to achieving benefits in the near term and practicality of implementation. The final chapter examines nonprice barriers and then presents recommendations for actions by either EPRI or the government to expedite the successful commercialization of TES.

3 *CHARACTERISTICS OF PRINCIPAL PARTIES*

3.1 *ELECTRIC UTILITIES*

Both operational and decision-making aspects of electric utilities affect TES commercialization. The operational aspects will be developed first, since these impact and underlay certain aspects of decisions. Publicly-held electric utilities provide over three-fourths of capacity, generation, and sales in the U.S.* Electric costs may be broken down into energy, demand, and customer-related components. The energy component consists of the cost of fuel required to produce electricity. The demand component consists of the plant required to meet peak demand: generating capacity, transmission lines, and that portion of the distribution network determined by demand. The customer component includes all customer-related costs, the distribution costs related to customer hookup, billing costs, overhead costs, etc.

Both energy and demand costs are affected by the peak electricity demand and load duration. Figures 1.1 and 1.2 show the annual load-duration curve and the peak-day load-duration curve for two actual utilities. Three general types of units are used to generate electricity: peaking, intermediate-load, and base-load units. The peaking units are cheapest to purchase and most expensive to operate; the base-load units are most expensive to purchase and cheapest to operate. Clearly, then, reducing the peak and raising the valley of the utility diurnal load duration curve will reduce fuel costs because fewer peaking and more base- and/or intermediate-load units will be required to service the load. Peak shaving will definitely reduce demand and save money. Because of these potential savings, an interest has developed in both TES and peak-load pricing, whose implementation is, in some form, critical to commercializing TES. The decision-making characteristics of private electric utilities also affect TES commercialization.

Neoclassical (or conventional) economic theory postulates that all firms are profit maximizers. Hence, utilities would be expected to be profit maximizers subject to the constraints of regulation.** This representation of actual utility operations does not seem adequate for several reasons. First, most utility management personnel are engineers or engineering-oriented so that system reliability and professional integrity are important goals. Second, the rate of return format, when adhered to strictly, holds dollar profit per dollar invested constant; hence, stockholders have no incentive, as long as utilities earn their allowed rate of return, to see profits rise.† Third, the "owners" of the utility differ from its operators and decision-

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*Public Power, p. 28 (Jan.-Feb. 1975).

**A theory revolving around this idea, known as the Averch-Johnson Effect, has been erected. See H. Averch and L. Johnson, *Behavior of the Firm Under Regulatory Constraint*, The American Economic Review *52*(5):1053-1069 (Dec. 1964)

†If the utility is allowed a range of, say, 13-16% return with any net profit over the 16% leading to rate reductions, this attitude clearly prevails.

makers.* Fourth, utilities are organized bureaucratically, especially the large utilities that provide the bulk of power, and, as such, tend to move cautiously and to place a high regard on safe and prudent policy.

If utility management does not aim at dollar-profit maximization, what are its goals? Its prime goal is to stay in business, and this purpose requires a sufficient dollar profit. Profit levels considerably above sufficiency are not tolerable, for they are apt to spark regulatory attention, resulting in reduction of the profit level to the necessary minimum. A modest profit cushion is thus sought. It allows room for error without arousing investor unrest or the need to seek a rate hike. Nor, at the same time, does a modest profit cause consumer or regulator dissatisfaction, which would result in, at minimum, rather unpleasant hearings and, at maximum, a rate and profit reduction.

Given sufficient earnings to raise capital, professional integrity and organizational requirements are two prime determinants of utility behavior.** Engineers and other professionals take a great deal of pride in doing a good job. "Utility operation engineers sometimes object to providing curtailable service, since they consider delivery of such power to be an affront to their ability to operate a reliable system."† Such professional integrity is good. It ensures real concern with the outcome of one's work and indicates satisfaction with doing the work, rather than merely working for pay. For utilities this has meant much concern with reliability and with performance of the total task of electric supply as well as, if not better than, other utilities.†† An enterprise as complex and demanding as the provision of electric power requires a great deal of specialization and, therefore, organization. In this context, virtually all decisions are group decisions, involving consultation with personnel at appropriate levels.± On the basis of these decisions, specialists combine to form consolidated views.

> It follows further, that anyone who is not a party to this collegial decision-making but who, nonetheless, seeks to alter or interfere with its decision will be doing so on the basis of inadequate knowledge.±±

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*While investors must receive a fair return, they do not necessarily have a say in management. Rather, capital can be thought of as being hired, much like labor, the firm being the hiring agent. See D. Ellerman, *The "Ownership of the Firm" is a Myth*, Administration and Society, 7(1):16-21 (1976). With public utilities, the profit, that which is left after "hiring" labor and capital, is in theory captured by the public as the result of regulation.

**See J.G. March and H. A. Simon, *Organizations*, Graduate School of Industrial Administration, Carnegie Institute of Technology (1968). In particular, pp. 150-154 present key insights into the interaction of these two factors.

†E.V. Sherry, *The Electric Utility Industry as the Bridge to Energy Stability*, paper delivered at the American Power Conference (Apr. 20-22, 1976).

††See March and Simon, *Organizations*, op. cit., p. 56, for insight into relative performance.

±J.K. Galbraith, *The New Industrial State*, especially pp. 71-83.

±±J.K. Galbraith, *Economics and the Public Purpose*, p. 81.

Thus utility management is very unlikely to pay heed to the advise of an "outsider."* Organizations require planning and, therefore, stable circumstances, which precludes changing their many facets simultaneously. This need for stability restricts the likelihood of widespread chance taking, although the concurrent necessity of growth and progress does incline the organization toward some innovation. However, any important innovative action requires wide internal support.**

Based upon these characteristics, utility resistance to the peak-load pricing concept, which was introduced into rate hearings by environmental inventors, is understandable.† When it is perceived that TES and associated innovative rates result in fulfilling the goal of sufficient profit, this resistance should fade. In addition, once a positive decision on peak-load prices and TES is made, organizational inertia, initially so hard to overcome, becomes advantageous.

Finally, when the utility perceives that a considerable new challenge is posed by the new rate format and its attendant technologies, its personnel will respond positively. Such response should occur with TES since the opportunities for load managing constitute important challenges to system engineers and production planners, while explanation of new and potentially advantageous rates should provide a source of satisfaction for marketing personnel. That these services will also aid the public should raise the self-esteem and sense of public spirit important to (and underlying many of the efforts of) public-utility personnel.

The publicly owned utilities sell about one-eighth of all electricity.†† Except for minimal concern with profits, they possess all the other characteristics of the public (privately owned) utilities. However, the many smaller systems (about 1/4 of sales) tend to have insufficient managerial talent, rather than organizational considerations, as a principal innovation constraint.†† Because they are publicly owned and therefore have as their charter goal maximizing public welfare, they should be more responsive to techniques that help reduce electric cost; however, because they are not regulated, the pressure mechanism for change is much weaker and thus they are, at present, more likely to be industry followers than leaders.

The rural co-ops provide about 5% of electricity sold to customers in the United States.†† Their characteristics are similar to those of the publicly owned utilities with the important exception that the rural electric co-ops have very low load factors, somewhat less than 50%. They therefore have a strong incentive to raise load factors, which includes facilitating thermal storage installation.

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*Though if the outsider persuades the Public Utility Commission, they of course will do so, albeit grudgingly.

**See Emery Troxel, *The Economics of Public Utilities*, S. S. Little & Co., p. 559 (1947), for additional personal-level reasons why innovation is unlikely.

†See (Wis 1974) 5 PUR 4th 28, Docket No. 2-U-7423 (*Madison Gas*).

††Public Power, pp. 29-70 (Jan.-Feb. 1975).

3.2 PUBLIC UTILITY COMMISSIONS

The basic legal rationale for public regulation is that such regulation be in the public interest and not be discriminatory or capricious (Nebbia v. New York, 1934). For electric utilities, the principal rationale is that they are naturally monopolic. That is, electricity cost in an area is lower with a single supplier. Regulation, therefore, is necessary to prevent abuse of this position.

The typical Public Utility Commission (PUC) is enjoined with the tasks of determining a "just and reasonable" rate for service and ensuring that such service be adequate. Service and price are interrelated; thus, if price is held low and the level of service drops, this is, in effect, equivalent to a higher price, at the existing service level.

In performing this task of regulation, the PUC faces pressures from the utilities involved and from the general public. As they function, these PUCs tend to view themselves as properly performing their role when neither the utilities nor the public is sufficiently dissatisfied to make organized protests. That is, they aim at the happy equilibrium when dissatisfaction with prevailing rates, services, and profits is low.* When the equilibrium is disrupted, the PUC sets about finding means to restore it. An example is the fuel-escalation clause in current rates. This clause allows the utilities to raise rates automatically as the price of fuel rises. Ideally, the clause reduces pressures brought on commissions by decreasing the frequency of rate hearings.

The commissions can be expected to continue to seek means to either reduce rate increases or make them more automatic, since either achievement will push them toward their desired goal of client group satisfaction.

Peak-load pricing tends to reduce rate increases by providing better cost signals to consumers, allowing them to modify their behavior accordingly. And thermal energy storage is an excellent means for customers to take advantage of off-peak rates, the key to effectively reducing capacity demand and, consequently the need to raise rates. If peak-load pricing appears to be effective, PUCs will implement it.

3.3 THERMAL-STORAGE VENDORS

There is currently a small thermal-energy-storage industry in the United States, composed primarily of the agents of large European storage-heater manufacturers.** Because of the existence of these European firms and their presence in the U.S. market, the problem of developing, demonstrating, and proceeding to mass production of storage space-heaters are virtually nonexistent.

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*See, for example, P.L. Joskow, *Inflation and Environmental Concern: Structural Change in the Process of Public Utility Price Regulation*, The Journal of Law and Economics, pp. 294-329 (Oct. 1974).

**One producer, Megatherm, Inc., in the hot water-radiator heater retrofit market is not serviced by the imported units.

The situation for hot-water heaters is also favorable. Several companies already manufacture storage units, while large units capable of interruption are commonplace. Cool storage for air conditioning, on the other hand, will have to proceed through the development process.

A small number of firms already are either selling imported units, or selling and manufacturing units. These firms are attempting to develop this market by selling units where rates are favorable, trying to get storage units accepted by code authorities, and lobbying for favorable rates. Given the availability of well-developed and tested units, the focus of activities will soon shift toward sales, since the other two activities are really subsidiary to the prime vendor concerns of profit and growth, whereas sales make up the key element in these goals.

3.4 CONSUMERS

The consumer is a critical actor in commercializing thermal storage. "...it is essential to remember that the primary focus for any new product must be on the consumer-purchaser and not on the infrastructure.... If a new product has merit in the marketplace from the viewpoint of the consumer, these other groups will respond to this need in an appropriate manner...."* There are three different consumer markets for TES: commercial establishments, homeowners, and renters. (A fourth, industry, has not been included in this study.)

The commercial establishment aims at profit maximization. One aspect of this policy is cost minimization, given minimal change in services rendered. Since any such cost reduction is reflected as increased profits, and as these establishments tend to be substantial consumers of power, especially peak power, they should be quite sensitive to any system that will reduce their costs.** Diurnal TES will achieve this reduction; however, interruptible service will seldom be acceptable because interruptions would often coincide with business hours.

The homeowner is concerned with reliable delivery of temperature control and hot water at a minimum price. Attention is also paid to attractiveness of devices. However, if reliable, convenient, comfortable, reasonably attractive, and low-cost devices are available, consumer response will be substantial. How substantial this response will be depends upon the customer's perception of the proper payback period and level of information. To implement

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*K.J. Thygerson, *Institutional Financial Barriers to the Widespread Commercialization of High Fixed Cost Energy Saving Heating and Cooling Equipment for Residential Housing*, Conference on Energy Storage, p. 2 (Feb. 1976).

**This is true to the extent that commercial establishments are operated by their owners. Where they have grown sufficiently large that agents of these owners are in operational positions, then cost minimization may be balanced off against agent preferences, thus slowing TES installation. See Harvey Leibenstein, *Aspects of the X-Efficiency Theory of the Firm*, The Bell Journal of Economics, pp. 580-606 (Autumn 1975).

adoption of a new technique, information is required -- in particular, availability, cost, and reliability of equipment; amount and derivation of savings on electricity; and value of equipment upon resale.* Once supplied with this information and assuming that TES meets all the above criteria, homeowners can be expected to make the necessary conversions where feasible and to demand such systems in new homes.

The rental situation is slightly different, for here the landlord is the owner of the facility. Therefore, the owner must be able to capitalize the value of installation either into rent or into the selling price of the property. This means that installation of TES devices depends upon the renters perceiving the advantages and effectively translating this demand to the landlord.

However, if heat is included in the rent charged, the incentive to install TES heating need not depend upon the perceptions of the renter. In this case, cost minimization for the landlord is the decisive factor.

Both homeowners and renters will adopt interruptible service, if the savings exceed their perceived value of interruptions. Since most users will not notice infrequent interruptions and dollar savings can be large ($30-100 per year for hot-water heaters), acceptance should be widespread once the rate and conditions are explained.

3.5 REAL-ESTATE DEVELOPERS

Real-estate development is a highly competitive industry. Because of this, developers must work to the dictates of the market. If consumers foresee sufficient benefits from additional expenditures to desire changes in present practices, then developers will make these changes. The current trend toward greater home and apartment insulation indicates this willingness to meet perceived needs. However, because the industry is highly levered there is an inclination to reduce risk by reducing first-cost.** Therefore, the developer has little leeway to gamble due to the large amounts of borrowed capital commonly used to finance construction. Developers will be reluctant to install thermal storage if it increases the initial investment, unless they feel that consumer demand will justify the risk. Because this is a regional, highly fragmented industry, the largest builder produces less than 1% of the annual supply of housing, response to new consumer demands will be slow.** The pattern of penetration is indicated by the old adage of 5% "innovators," 15% "influentials," 60% followers," and 20% "diehards" or "laggards."†

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*Effective dissemination of information to consumers is by no means an easy task. It requires much ingenuity, skill, and sometimes direct demonstration.

**Alan Hirschberg and Richard Schoen, *Barriers to Widespread Utilization of Residential Solar Energy, The Prospects for Solar Energy in the U.S. Housing Industry,* Policy Science (Dec. 1974).

†S.F. Otteson, W.G. Panschar, and J.M. Patterson, *Marketing: The Firm's Viewpoint,* McMillan Co., New York, pp. 147-48 (1969).

3.6 FINANCIAL INSTITUTIONS

The lending institutions include banks, savings and loan companies, credit unions, and insurance companies. Savings and loan companies tend to dominate the home market, and banks are dominant for commercial establishments and industry. Since industry, and, to a lesser extent, commercial establishments already have life-cycle costs of ownership included in loan considerations, the most important impact of lending institutions is upon the home market. Similar characteristics do, of course, apply to other TES possiblities. Lending institutions are profit maximizers, subject to constraints upon risk imposed by federal regulations. They must, therefore, balance the level of loan repayments, recipient's income and assets, value of collateral, and going interest rates to determine whether to make a loan. The crucial question for TES is value of collateral. A recent study on lending institutions indicates that high-first-cost energy-conserving devices have four major concerns: (1) evidence on expected life of systems, (2) added initial cost of the system, (3) information on expected performance, and (4) life-cycle cost of the system.* If thermal storage satisfactorily meets these concerns, there would still be a marked reduction in installations without adoption of appraisal based upon life-cycle costs.

If no attention is paid to the life-cycle costs of housing, that is, not only construction costs but also operating costs, then the savings from TES will not be capitalized into the value of the home. This situation will result in consumers requiring a higher rate of return of TES than that which reflects true social costs. The adoption of life-cycle cost will be spearheaded by appraisers who, acting in close contact with lending institutions, are critical in determining the mortgage values of housing. Of course, such appraisals cannot be too far in advance of consumer perceptions. Nonetheless, the adoption of life-cycle costs into home value determination will be an important aid in the commercialization of thermal storage and all other energy-conserving devices.

3.7 COMMERCIALIZATION BARRIERS

Given the characteristics of the principal parties involved, we have demonstrated that there are three commercialization barriers in addition to lack of available air conditioning storage devices: (1) electric rates, (2) information dissemination, and (3) institutional lags. Of these, rates are most important since they provide the necessary incentive to consumers.

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*R.W. Melicher, *Lending Institution Attitudes Toward Solar Heating and Cooling*, unpublished paper, found in K.J. Thygerson, *Institutional Financial Barriers to the Widespread Commercialization of High Fixed Cost Energy Saving Heating and Cooling Equipment for Residential Housing*, Conference on Energy Storage (Feb. 1976).

4 ELECTRIC UTILITY RATES

4.1 RULES AND PAST PRACTICE OF RATE SETTING

As has been indicated, the existence of off-peak rates is the key to commercializing TES. Nevertheless, rates must be set in a proper and justifiable fashion.

Eight widely accepted criteria for a sound rate structure are:*

1. The related "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.

2. Freedom from controversies as to proper interpretation.

3. Effectiveness in yielding total revenue requirements under the fair-return standard.

4. Revenue stability from year to year.

5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers.

6. Fairness of the specific rates in apportionment of total costs of service among the different consumers.

7. Avoidance of "undue discrimination" in rate relationships.

8. Efficiency of rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:

    a. In control of the total amounts of service supplied by the company.

    b. In control of the relative uses of alternative types of service.

Of these eight criteria, items 3, 6, and 8 are considered basic.*

These criteria were used in establishing the prevailing rate structures: declining block rates for small users, demand charge rates for larger customers, and interruptible rates for a limited number of hot-water-heater customers and for certain industries.

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*James Bonbright, *Principles of Public Utility Rates*, pp. 291-292 (1961).

These rate types were introduced, because, given past levels of demand, costs of metering, and marginal electricity costs, they were an efficient means of transmitting the cost of electricity consumption. To reiterate, the three principal categories of cost are: operating costs, demand costs, and customer costs. The operating costs are the costs of the fuel and labor required to produce a kilowatt hour of electricity. The demand costs are the cost of generation transmission, and some distribution capacity. Customer costs are the costs of hookup, metering and general overhead, and the remainder of distribution expense.

Declining block rates have typically consisted of a small initial charge, to reflect customer charges, and then prices per kilowatt hour that declined in stepwise fashion as shown in the example below.

Sample Declining-Block-Rate Structure
for Monthly Consumption

Initial charge	$1.00
First 100 kWh	0.030
100-500 kWh	0.022
500-1000 kWh	0.018
>1000 kWh	0.015

This structure was felt to be an adequate representation of costs for four reasons:

1. The distribution- and transmission-network costs were a high proportion of total system costs that resulted in high fixed costs, so that the cost of additional consumption was lower than average.

2. Economies of scale were attainable in generation, therefore added consumption lowered average costs.

3. Technology was advancing rapidly, resulting in lower costs if the new techniques could be applied.

4. Metering costs were high compared to other system costs.

The demand charge rate has been applied to larger users where added usage made increased metering cost relatively small. It consists of a fixed charge to cover customer costs, a flat kilowatt-hour charge that reflects operating costs, and a charge for maximum demand per billing period. The maximum demand is based upon a specified period, generally 15 minutes. The most common system is to charge for the maximum demand per month with a rate ratchet to include the maximum demand per year. This ratchet works in the following fashion. The customer is responsible for paying the demand charge for a certain percent of highest monthly demand for the next 11 months. Thus, if peak demand in May is 100 kW and there is an 80% ratchet, then for all subsequent months in which the peak demand is less than 80 kW, the customer pays for at least 80 kW. If demand exceeds 100 kW in one of these months, then 80% of that demand is the new ratchet. Should peak demand fall within 80-100% of the previous peak, then just the monthly peak usage is charged.

Some utility charges do allow night peak demands greater than the daytime maximum. For example, consider a customer for whom a 50% extra night demand is allowed; the peak might be 149 kW at night, but if the daytime peak is 100 kW, the latter demand determines the charge.

Interruptible rates pass through to the consumer the lower cost for generation that occurs during off-peak periods. The customer receives a lower rate, but in return the utility is allowed to interrupt service for up to a specified number of hours per day. This rate has been adopted for some industrial customers and for some domestic hot-water heaters. Although more common in the past, several utilities give lower rates for hot-water heaters.

Finally, all-electric homes have been offered lower rates in many areas. This offer reflected a favorable effect upon system load and, therefore, costs.

Although these rates provided adequate revenues, they no longer appear to reflect actual costs as well as another pricing scheme, peak-load pricing.

4.2 *THEORY OF PEAK-LOAD PRICING*

What is the proper pricing technique when technological conditions preclude storage, requiring, therefore, sufficient capacity to meet peak demands? This question, the question of peak-load pricing, is an old one, as is the solution for the simplest situation. For this case, the technology meets the above description: fixed demands in two periods, ability to add capacity continuously, only one production technique, and no informational costs. This case is easily solved by applying the principle of marginal cost pricing; as a result, all capacity costs (B) must be borne by the peak-period users, while incremental unit operating costs per period (b) are borne by *all* users. The rationale is as follows. Assume that another user is added during the off-peak period. Since there is no need to expand capacity for this consumption, the cost to society is merely the incremental cost of supply (b), which therefore should be the price. For additional consumption on-peak, however, more capacity is needed, and hence the cost of this capacity (B) should be borne by all users on-peak. That is, since all peak users could refrain, all are marginal; hence, all should pay the cost of capacity. The peak-period price, therefore, is the period operating costs (b) plus the capital cost per unit (B). The unit pricing equations are:

$$\text{Peak Period} \quad p = b + B \tag{1}$$

and

$$\text{Off-Peak Period(s)} \quad p = b. \tag{2}$$

This prescription ignores questions of shifting peaks, addition of capacity in discrete amounts, and the availability of more than one production technique.* If all capacity costs are placed upon the peak period and the result is that demand in the off-peak period exceeds that in the peak period, a shifting-peak case exists. To offset this effect, prices should be set

*For a more complete statement of the theoretical approach to these problems, see Appendix II.

such that the sum of the prices equals operating expenses plus B, the capacity cost when capacity is fully utilized. The discrete nature of production techniques implies that capacity should be added when the sum of its added value to consumers and increased costs to producers is positive, thus maximizing social welfare. Price is set equal to the operating cost of the highest-operating-cost production technique on line when two or more production techniques exist, except for the peak period when price includes the operating cost of the peak-production-mode plus the capital cost of that mode, divided by the hours of use. Prices are set in this fashion because, in an optimally planned system, the total cost for the peak mode and the next-least-operated mode are exactly equal at the maximum number of hours per year for which peaking units are run. That is, for the maximum number of hours the savings in operation from operating the second mode equal the increased capital cost of that mode over peaking units.

A simple numerical example shows that for an optimal system with fixed peaks, peak-pricing is not only efficient, but it also meets all three basic rate criteria: adequacy, efficiency, and equity. Assume the existence of a utility with the load-duration characteristics of Fig. 4.1 and costs shown in Table 4.1. The efficient pricing rules (as derived earlier) are to charge operating cost of the highest operating cost mode in use for all but the peak period; the hourly peak-period charge is the hourly peak operating cost plus the capital cost of a peak unit divided by the number of hours of operation. This yields the prices listed in Table 4.2. These rates do in fact meet criterion 3, adequacy, since revenue and costs are equal at $349.18, as shown in Table 4.3. These rates are eminently fair. Suppose consumers used 1 kW for 8760 hrs. They should be considered responsible, therefore, for a unit of base-load capacity and clearly should pay for this unit, no more and no less. As Table 4.4 demonstrates, this is precisely the case. An examination of revenues derived eliminates any doubts of the efficiency of this pricing scheme and these rates indicate to the consumer that peak power uses more resources.

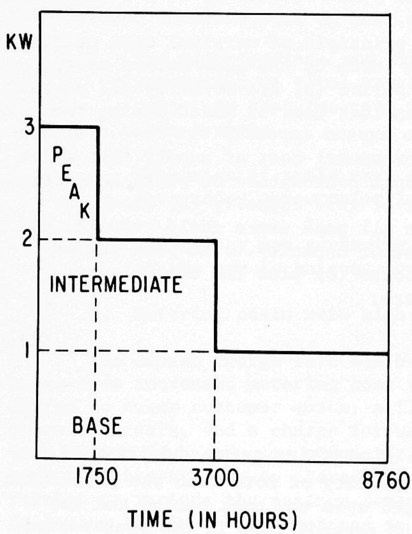

Fig. 4.1 Hypothetical Load-Duration Curve for Optimal System with Three Generating Techniques

However, when this elegant theory is applied, many problems arise. In fact, many of the assumptions such as no interdependence of demands, no information costs, and stable technologies do not correspond to reality. The most important problems and their implications for pricing are, therefore, presented. These are: information costs, the question of historic costs versus long-run incremental costs, and simplicity and stability of the rate

Table 4.1 Unit Types, Costs, and Hours of Operation

Unit Type	Annual Capital Cost/kW($)	Hourly Operating Cost($)	Hours Operated	kW Capacity
Peaking	20	0.034	1750	1
Intermediate	48	0.018	3700	1
Base	85	0.008	8760	1

Table 4.2 Hourly Prices for Operating Periods

Period	Price($)	Type of Cost
Peak	0.04543	Peak Operating Cost + Capital Cost/1750
Intermediate	0.01800	Intermediate Operating Cost
Base	0.00800	Base Operating Cost

Table 4.3 Adequacy of Peak Load Prices

Utility Costs	
Capital Costs (all 3 units)	$153.00
Operating Costs	
Peak (1750 hr × $0.034/hr)	59.50
Intermediate (3700 hr × $0.018/hr)	66.60
Base (8760 hr × $0.008/hr)	70.80
Total Cost	$349.18
Utility Revenues	
Peak Period (1750 hr × $0.04543/kWh × 3 kW)	$238.50
Intermediate Period (1950 hr × $.018/kWh × 2 kW)	70.20
Base Period (5050 hr × $0.008/kWh × 1kW)	40.48
Total Revenue	$349.18

Table 4.4 Utility Costs and Revenues from a Customer Using 1 kW for 8760 hrs

Cost	
Capital Cost (base unit)	\$ 85.00
Operating Cost (8760 hrs × \$0.008/kWh)	70.08
Total Cost	\$155.08
Revenue	
Peak Period (1750 kWh × \$0.04543/kWh	\$ 79.50
Intermediate Period (1950 kWh × \$0.018/kWh)	35.10
Base Period (5060 kWh × \$0.008/kWh)	40.48
Total Revenue	\$155.08

structure. The information costs are most significant and can be broken into three groupings: metering, utility questions, and customer questions.

4.3 INFORMATION COSTS

From the economist's view, the aim of instituting peak-load pricing is efficiency. It is a means of maximizing social welfare, attaining maximum global benefits for society. Clearly, if one assumes that information collection (metering) is free, and it is in fact expensive, a wrong policy prescription will be made. More sophisticated metering devices are required to institute peak-load (time-of-use) rates than the simple kilowatt-hour meters currently installed in residences. Therefore, the potential benefit must exceed the additional metering costs, so that a social net benefit results. A net gain may not exist for all users, since low-usage customers have less opportunity to reap the benefits, but face the identical metering costs of larger-usage customers. This situation existed in a British tariff experiment in which benefits did not exceed added metering costs. However, average usage for participants was about three-fourths of *average* U.S. residential consumption and many who could benefit from time-of-use rates were already on a special rate and thereby excluded from this study.

Control technology for implementing load changes, either by the utility or the customer, must be included in the above welfare equation. If we examine both residential consumption and costs of metering and control for residences (see Appendix III), there are many consumers who consume sufficient electricity to justify time-of-use rates.

Rational customers value their time and consider that the time required to understand new rates and to respond appropraitely represents a cost. For this reason, consumers prefer simple, convenient, and stable rates. (The question of stability is dealt with in Sec. 4.5.) Keeping rates simple is not an attribute of pure peak-load pricing. At the extreme, this could mean 8760 different rates, one per hour, which is not acceptable. At present, rate makers seem to believe that three diurnal rates with seasonal variation is the maximum complexity tolerable (proposed rates are explored in Sec. 4.6).

Customers also must be aware that the rates, or at least the rate format and approximate rate break, are stable. Demand for electricity is related to its usefulness in performing various functions, and as such is a derived demand dependent upon appliances, etc. This means that the demand is primarily the result of consumer decisions to purchase durable items that are powered by electricity, such as furnaces, water heaters, lights, stoves, and clocks. Since these items have long lifetimes, there must be assurance that radical rate changes will not be continually occurring. This consumer forecasting requirement is also an argument for a simple rate format, because the more rates, the more difficult it is to determine the consequence of an action. Particularly, when appliance costs are small, the benefits of analysis are unlikely to outweigh the cost of the time involved in the decision.

Responding to price changes requires information about available equipment. Consumers must know what is available that can meet their needs at a lower total cost considering rates. This acquisition of knowledge calls for a large time commitment by the individual or a large informational campaign by the utility. Experience in Europe indicates the importance of disseminating information, for those utilities that were most active in promoting devices to take advantage of the rates showed considerably greater load-factor improvements than those that were less active.*

The utility faces several informational costs, the key one being determining the time of peaks with respect to prices. Two factors are involved: weather sensitivity and pricing sensitivity. At present and for the foreseeable future, electric loads are highly weather-responsive. Due to space conditioning, utilities have higher demands in summer and winter than in autumn and fall. Although most U.S. utilities currently face summer peaks, the trend to electric heating due to natural-gas unavailability will be reversed in the 1980s. In either case, the precise time of summer peak is not predictable before the fact. What is predictable are the period and times within which this peak will occur. For example, for a summer peaking system the peak (with constant rates) will fall somewhere between noon and 9:00 p.m. on a weekday between June 15 and Sept. 15. Since prices must be before the fact and readily understandable, this means equal pricing of all hours with a high probability of being on-peak at the peak rate. Thus, rate making requires knowledge of loss of load probabilities and consumer responses to price. These responses are presently uncertain, and continuing research on rate policies is being carried out.

The first effect of peak-period pricing is to shift peaks into periods immediately following the peak. Thus, the peak-priced period must be expanded to account for this shifting peak. This shifting peak also raises the question of interdependent demand. TES indicates that demand is interdependent, since an off-peak price differential will induce shifts in consumer behavior in response to this differential. However, because of the broad pricing period used, a noteworthy impact will occur only if enough load is shifted to the time either immediately before or after the peak prices go into effect.

A potential problem when the peak rate occurs over a wide range of hours

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*See J.G. Asbury and A. Kouvalis, *Electric Storage Heating: The Experience in England and Wales and in the Federal Republic of Germany*, Argonne National Laboratory Report ANL/ES-50 (May 1976).

is the needle peak. Customers will respond to peak pricing by equating the value of benefits to the peak-period price, which due to its nature still undervalues somewhat the costs of the actual peak. Thus, on those "worst" days they will have higher consumption than is efficient, and on other days when price is greater than costs, demand will be lower than is optimal. This type of fluctuation accentuates the difference between the system peak and high-use periods leading to a "needle peak," a very short-duration peak period of considerably higher magnitude than other times. This problem is greatest for summer-peaking utilities. The variance in demand is much greater in summer, since the temperature differential between that desired indoors, and ambient, is smaller. Furthermore, the number of days when air conditioning is required is lower, and because buildings store heat during a succession of several hot days, that additive load also needs to be taken into account.

In either the winter- or summer-peaking case, therefore, there will be short unpredictable periods of time when it would be worth a great deal to the utility to reduce load. The utility is a complete system and should adjust prices to reflect total system costs. Such adjustments resulted in differential rates based upon cost of service in the past. Offering an interruptible rate informs customers of the potential savings. Customer response to this rate enables the needle peak problem to be alleviated and possibly eliminated.

4.4 LONG-RUN INCREMENTAL COSTS

The utility does face another key problem, the forecasting of future costs. Peak-load pricing, from the purist's viewpoint, is synonymous with marginal-cost pricing. And properly done, this means that prices should be based upon the long-run marginal costs. However, given the incremental nature of additions to utility systems, the applicable concept is actually long-run incremental costs (LRIC).

Pricing on the basis of LRIC, however, is fraught with problems. Some doubt exists as to the proper time frame to use due to increasing uncertainties over time and the question of the "correct" social discount rate. This decision must be based on such practicalities as how long can data be considered reasonably accurate and how far into the future can planning based on today's consumption assure that capacity will be available to meet demand. A much more serious problem arises when LRIC are divergent from the embedded historical costs. The adequacy requirement is violated if LRIC are less than historical costs, or excess profits result if they are greater. There is, however, a theory that states how prices should deviate from LRIC prices when LRIC differ from historic costs. This theory is the inverse-elasticity rule, which states that deviations from marginal costs should be greatest for inelastic customers. Its purpose is to change demand as little as possible from what it would be with marginal-cost pricing. Customer-related costs are highly inelastic; that is, customers are willing to pay a great deal to hook up to the utility and are not likely to vary consumption based on this price unless it becomes prohibitive. Therefore this cost classification should be the first price adjusted. If the adequacy requirement cannot be met by adjusting customer costs, then, to properly follow this rule, elasticities must be with respect to demand and consumption.

4.5 STABILITY

Peak-load pricing also leads to unstable rates. Rates are not unstable, however, in the sense of requiring increases, but rather as a reflection of shifting to peak use. Clearly, the value of the first hour shifted from peak to off-peak is quite large. However, as load curves flatten, the resultant savings from such a switch diminish. This abatement indicates that the differential in rates should narrow as such rates succeed in attracting off-peak customers and that the hours of peak prices need changing to reflect the new conditions.

The two or three period rates expected should not provide a problem initially, since consumers take several years to respond fully to electric rate changes. But at some point, severe problems with customers could arise as the result of rate and time rearrangements. Because of the nature of electric appliances and TES devices, customers need several years of reduced off-peak rates to justify purchase. Hence, either a specified rate break or agreement as to rate differential is required. And the greater the customer investment required, the greater the need for assurance, which involves advance planning by utilities to limit such rate changes, and announcements that this is in fact the case.

Another rate-destabilizing impact not accounted for by the pure theory is technological change. Suppose that a new efficient technology is developed; then, for the time period for which this device would be used, the price should fall.* This could work well for large customers whose demand levels justify the price change, but the stability and simplicity needs of small customers would call for a slightly different approach. Undoubtedly, the best technique would be to roll the new technology into the existing structure.

Thus, although peak-load pricing is the correct principle because regulation aims at greatest social welfare, it must remain the principle underlying an art. Actual rate making must proceed with a view toward what is practical.

4.6 ALTERNATIVE MODES OF PEAK-LOAD PRICING

Each one of several potential means of peak-load pricing is useful, depending on total customer usage, peak demand, available equipment, and relative costs of metering versus plant. The principal rate types are seasonal rate variations, demand charge time-of-use rates, and load-management rates.

The seasonal-variation rate is least expensive to implement, since it requires only the standard single kilowatt-hour meter in common use. Rates are set highest for peak months and lowest for those off-peak, with possibly an intermediate rate for near-peak months. Thus, as currently proposed, these rates for a summer-peaking utility involve highest rates in summer, somewhat

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*Effects of improvements in existing generating devices are already included in forecasts of LRIC. Should an unexpected development occur, however, the above will apply.

lower rates in winter, and lowest rates for the base autumn and spring months. Table 4.5 contains the proposed Wisconsin Electric Power rates that follow this format. These rates are best for customers for whom metering, control, and attendant information costs outweigh the benefits of more specificity as to costs of service.

Time-of-use rates are more sophisticated and require somewhat more sophisticated metering. These rates involve varying rates by season, by time of day, and, ideally, by time of week to provide a better reflection of system loads. (See the optional off-peak rate in Table 4.5.) Thus, with a two-rate scheme, those peak or potentially peak hours, due to shifting, receive a high rate, while low-use hours are charged off-peak rates. Since weekends are predominantly off-peak, they also receive the off-peak rate.

Table 4.5 Proposed Time-of-Use Rates,[a] Wisconsin Electric Power Co.

Type of Rate Electricity Use	Energy Charge in ¢/kWh: Summer (July, Aug., Sept.)	Winter (Jan., Feb., Mar.)	Base (All Other Months)
Standard Rate Customer Charge per Month: $2.75			
First 500 kWh/month	4.20	3.01	2.32
Next 500 kWh/month			
Without Water Heating	4.20	3.01	2.32
With Water Heating	3.57	3.23	1.63
Over 1000 kWh/month	4.20	2.18	1.87
Optional Off-Peak Rate[b] Customer Charge per Month: $2.75; Meter Charge per Month: $2.50/meter; and Water Heating Credit: $1.50/month			
First 500 kWh	7.69	5.10	3.71
Over 500 kWh	7.69	4.50	3.41
Low-Use Hours	0.946	0.946	0.946

[a] Condensed from rate schedule presented in D-6630-ER-2; Wisconsin Public Service Commission.

[b] High-Use Hours: 7 a.m.-9 p.m. Monday-Friday, inclusive.

This rate is more preferable for larger consumers than for those for whom the seasonal rate works best, that is, those customers who feel they can respond sufficiently to benefit from the off-peak period price.

Demand charges of the conventional type indicate to the consumer that an even load is preferable. But not transmitted is the more important information that at certain times demand can be handled more or less cheaply. A far better scheme involves pricing demand upon a time-of-use basis, since it provides such information. An example of a demand-charge rate of this type, again from Wisconsin Electric Power, follows. Note that the energy charge is not seasonal, since only marginal running costs must be covered. Although some feel that due to increased metering cost over kilowatt-hour rates, large electricity usage is required for this rate, such a rate is currently being proposed by the Virginia Electric Power Co. for residential and small commercial customers. In short, with sufficient power requirements, demand rates are more desirable than a kilowatt-hour rate, because they provide better information about the cost of using electricity.

Table 4.6 Proposed Time-of-Use Rate Incorporating Demand Charge, Wisconsin Electric Power Co.[a]

	Customer Charge per Month: $15.00		
	Energy Charge		
	Summer (July, Aug., Sept.)	Winter (Jan., Feb., Mar.)	Base (All Other Months)
All kW/month	$5.10/kW	$1.70/kW	$1.70/kW
High-Use Hours[b]			
0-50,000 kWh	2.44¢/kWh	(Same for All Seasons)	
Next 450,000 kWh	2.24¢/kWh	" "	" "
Over 500,000 kWh	1.74¢/kWh	" "	" "
Low-Use Hours - All Other Hours, Off-Peak	0.89¢/kWh	" "	" "

[a]Condensed from rate schedule presented in D-6630-ER-2; Wisconsin Public Service Commission.

[b]Billed demand is customer's 15-min. maximum demand between 7 a.m. and 7 p.m. Monday-Friday (i.e., during high-use hours), all seasons.

Load-management rates may or may not require a separate contract; they cover two types of service, off-peak use or interruptible. The prime purpose of such contracts is to provide better price signals to customers than the more generalized rates. This service requires special equipment and/or special production arrangements. For interruptible users, the customer must be able to operate during the interruption period or feel that the price break justifies being interrupted. For off-peak rates, the advantage must be sufficient to cover the cost of required specialized equipment, such as that required by TES. For the latter case, the contract can provide assurance that a rate break will be of sufficient size and duration to cover increased capital outlays. The contract also provides assurance of proper operating conditions for both customer and utility. Appendix IV is an example of such a contract, the Electric Load Management Agreement, currently used by Green Mountain Power Company.

There are, therefore, a number of potential rate types. Each has certain advantages, and all can and should be used to provide electric service at lowest possible cost. Such a flexible approach to rate-making, one employing all these options, has worked well in England and Wales. There, by using time-of-use rates, interruptible rates, off-peak rates with utility control, time-of-use demand charges, and energy charges, in addition to declining block rates, the Central Electric Generating Board was able to raise the peak-day load factor from 71% in 1957 to 83% in 1973.* Had the load curve on the peak day in 1973 been the same as in 1957 and had total energy demand on that day equaled that recorded on the actual 1973 peak day, the peak demand would have been 47.1 GW rather than 40.4 GW, that is, 16% higher than was experienced. Such impressive results indicate the potential benefits possible with peak-load pricing.

4.7 REVIEW OF STUDIES IN PROGRESS

Because rate-making is an art and there are numerous possible rates, each having a role in an efficient utility-rate structure, a great deal of information on rate design, consumer response, metering, and all other pertinent matters is required. Fortunately, this task is well underway.

Many utilities have begun their own investigations of various aspects of peak-load pricing. The Federal Energy Administration is sponsoring (in part) a number of such studies, and the Electric Power Research Institute (EPRI) also has a peak-load pricing study underway.

4.7.1 FEA Studies

The Federal Energy Administration is currently funding electricity rate and conservation studies in 10 states, with plans to increase this

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*D.L. Walker, *Design of Electricity Tariffs in England and Wales and Their Experience in Application*, Proc. Energy Systems Forecasting Planning and Pricing, French-American Conf., University of Wisconsin, Madison, pp. 329-335 (Sept.-Oct. 1974).

number shortly. Of these, nine (Arkansas, Arizona, Connecticut, California, New Jersey, New York, Ohio, Vermont, and Wisconsin) involve time-of-use rates, while the tenth (Michigan) is aimed at load management and energy conservation for industrial customers. The Ohio and Vermont studies also involve thermal storage and its effect upon utility load and costs.

The primary aim of most of these studies is to assess consumer response to time-of-use rates, especially elasticity of demand. Consequently, rates have been designed primarily to test demand elasticity, rather than to reflect costs. The two most pertinent studies are in Ohio and Vermont, since both include load management.

The Ohio experiment involves development of time-of-use rates based upon long-run incremental costs and two different approaches to thermal storage for load management.* A computer program to determine incremental costs of electricity production is currently being refined. Another model to simulate impacts of moving industrial load is under development. Additionally, an experimental rate for residences, based upon incremental costs, has been filed.

Radio-control switching of loads uses the thermal store of the house or water heater to shave peaks. The air conditioning interrupt system will defer home units for up to 27 min. in an hour.** The study will determine the impact of such controls on system load characteristics and costs. In addition, hot-water heaters will be deferred for up to 4 hrs. Buckeye Power Corp., one of the participants, currently has 10,000 homes on radio control and is expanding to 40,000, its entire water-heating load. On January 13, 1975, at 5:30 p.m., all 10,000 electric hot-water heaters were switched off for 3 hrs and 45 min. This load deferral of 14,000 kW saved about $500,000 or $35/kW. This was done with minimal inconvenience; only four or five customers complained.

Vermont is easily the most advanced state with respect to its study, having at least an eight-month lead on other studies. Its study involves the investigation of responses to various time-of-use rates and installation of utility-controlled, commercially-available, TES home-heating systems. This work is being performed by Green Mountain Power Co.; the state's other major utility, Central Vermont, has also implemented both time-of-use rates and utility-controlled TES systems.

Green Mountain Power Corp. introduced six general-use experimental rates: an inverted-demand rate, a peak/off-peak rate, an interruptible rate, a three part rate, a peak-kilowatt demand rate, and a contract rate.

Experience has so far revealed the three demand-charge-based rates--the inverted-demand rate, three-part rate, and contract rate—to be an

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*Proposal, Demand Management Demonstration Project, submitted to Office of Energy Conservation and Environment, Federal Energy Administration, by Public Utilities Commission of Ohio, pp. 14-16 (March 7, 1975).

**Air conditioning deferral is also being investigated in Arkansas.

ineffective means of load management.* In short:

> Because of the continuous sharp spikes that consistently happen during the system peak-load periods, demand charge rates appear to be an ineffective means of load management, short of the possible positive effect of introducing load limiting devices.**

However, these demand charges are not for the peak, but for all day. The peak kilowatt rate was successful in reducing peak loads, although it was not popular and when GMP extended its off-peak rates, all those on this rate switched over. Information to date is, therefore, inconclusive on the feasibility of combined kilowatt and kilowatt-hour time-of-use rates for residential and other small users.

The off-peak rate, on the other hand, has proven so promising that, as of March 5, 1976, Green Mountain Power Corp. is offering it as an option to all residential customers. The rate is presented in Table 4.7.

Table 4.7 Green Mountain Power Corporation Off-Peak Rate[a]

Customer Charge:	$5.50 per month		
Energy Charge:	On-Peak Hours (between 7:00 a.m. and 9:00 p.m.)		
		First 200 kWh	2.40/kWh
		Next 470 kWh	5.00/kWh
		Over 670 kWh	3.60/kWh
	Off-Peak Hours (between 9:00 p.m. and 7:00 a.m.)		
		First 100 kWh	2.40/kWh
		Next 330 kWh	1.50/kWh
		Over 430 kWh	0.08/kWh

[a]Green Mountain Power Corp., *Investigations Into the Effect of Rate Structure and Heat Storage Units on Customer Electric Usage Patterns*, Progress Report III, submitted to the Vermont Public Service Board, p. 18 (Dec. 2, 1975).

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*The inverted-demand rate bills solely on peak customer demand and on an inverted basis; the actual charges are:

First 3 kW of demand per month @ $4.20/kW
Next 3 kW of demand per month @ $7.00/kW
All over 6 kW of demand per month @ $8.40/kW.

So far, customers have found this a difficult rate, since large appliances such as dryers have very large demands. And the effect upon system load has been minimal. The three-part rate includes a customer charge and an energy charge, which, however, is considerably lower than that above. The contract rate is a flat $4.25/kW or fraction thereof for 1-10 kW, plus a customer charge of $5.50; customers with demand in excess of 10 kW are not allowed.

**Green Mountain Power Corp. *Investigations Into the Effect of Rate Structure and Heat Storage Units on Customer Electric Usage Patterns*, Progress Report IV, submitted to the Vermont Public Service Board, p. 7 (Mar. 4, 1976).

Customer satisfaction with the off-peak rate has been excellent. (Central Vermont has also had a great degree of customer satisfaction with its off-peak rate.) As can be seen from Fig. 4.2, showing system and off-peak rate loads, there is a benefit to the utility from this rate as demand is shifted away from the peak hours. The one disadvantage, however, is that there is a rather sharp peak in the 2 hrs following the peak-price period.

The interruptible rate is a promising load-management technique. As currently designed, customers receive a $5.75 per month credit in exchange for disconnection of hot-water heaters from 9:00 a.m. to noon and again from 5:00 to 7:00 p.m. This rate has proven effective at shifting load from system peaks and is popular and easy to administer. The study is being expanded to include the benefits of more precise control of interruptions through use of ripple control.

There are two aspects to the thermal-storage part of the study -- ripple control and home heating. The ripple-control receivers have been installed, and testing began in March 1976. The heat-storage systems are hydronic units commercially available from Megatherm, Inc. All units have been placed in service, but no data are currently available. In addition, a number of the magnesite brick units are in place on Green Mountain's network so that the two types can be compared.

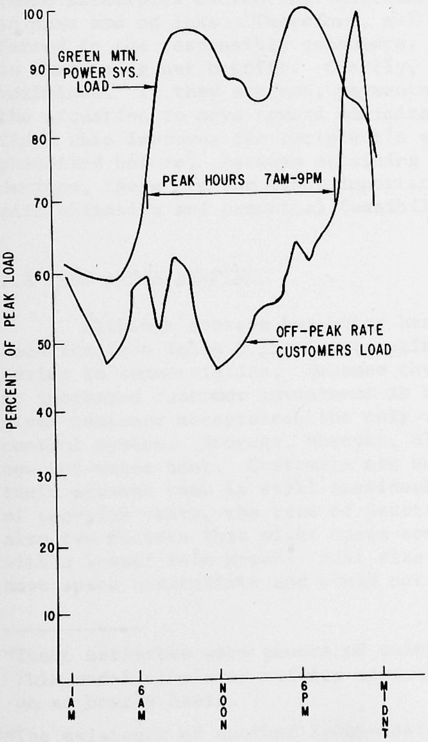

Fig. 4.2 Green Mountain Power Co. System Load and Load for Customers on Off-Peak Rate

4.7.2 *EPRI Studies*

The Electric Power Research Institute has underway a 10-part investigation of rate design covering all aspects of rate-making. The 10 parts can be divided into four segments: (1) various aspects of time-of-use rates, (2) metering and control technologies, (3) technologies available for utilizing peak-load price, and (4) customer acceptance of rates. The various aspects of time-of-use rates include analysis of various pricing approaches, an investigation of demand elasticity for electricity, an investigation of and help in facilitating rate experiments involving smaller customers, development of a costing methodology for peak-load pricing, rate-making, and determination of potential cost advantages of peak-load pricing. The metering and control-technology studies will inventory existing equipment to see what is required and what can be adapted for peak-load pricing, appraise electronic metering, evaluate effectiveness and applicability of mechanical controls at customer premises, and evaluate penalty pricing. The technology studies will review equipment that can use peak-load pricing to advantage, review load-shifting potential for larger customers, and propose research into promising areas. The customer-acceptance study will assess customer reactions and examine technical, economic, and behavioral constraints on rate changes as well as the role of customer-information programs.

5 *DEFINITION OF BEST RATE STRUCTURES FOR TES*

5.1 *CRITERIA FOR DETERMINING BEST-RATE STRUCTURES*

Maximizing social welfare, attaining the greatest net benefits for both the utility and customer, is the prime criterion in choosing the mode to commercialize TES. Estimates of these benefits have been made for four utility service areas.* These are presented in Table 5.1. Of the four utilities involved, A and B are winter peaking and C and D summer peaking. Thus air conditioning storage TES for service areas A and B and space heating TES for service areas C and D are uneconomical. The discharge periods presented are those offering the greatest net benefits. As can be seen with only two exceptions, social welfare, the value of utility savings less payback required to commercialize, is positive. Therefore, TES is desirable.**

Determination of the best rate structure to commercialize storage must be based upon the principles of proper pricing. As demonstrated earlier, these principles decree that customers should pay for costs incurred by them, no more and no less. Therefore, all utility-costs savings should be transferred to the responsible consumers. Within this context, the prime objective is maximizing net benefit. Clearly, society is best off when benefits are maximized. If they are not, payments could be made to those responsible for the situation to move toward maximization without affecting anyone else. Since this improves the recipient's welfare, it is a better situation than prevailed before. Because attaining these benefits requires installation of devices, there are two other important rate-setting criteria: ease of commercialization and practical feasibility.

5.2 *HOT-WATER HEATING*

Although storage hot-water heating yields greater monetary social benefits (see Table 5.1), interruptible service is considerably quicker and easier to commercialize. Because the utility will pay for the control device, no increased customer investment is required for interruptible service. Thus, given customer acceptance, the only delay is the time required to install the control system. Storage, however, also requires increased investment in a new hot-water tank. Customers are unlikely to make this investment while their present tank is still serviceable. Since hot-water tanks have lifetimes of ten-plus years, the rate of penetration will be much slower. There are also two factors that might cause consumers to prefer interruptible service with a lesser rate break: unit size and convenience. Some customers may have space constraints and would not be able to install the bulkier storage

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*These estimates were generated using SIMSTOR, a storage simulation model. This model simulates utility operations, including maintenance requirements, on an hourly basis.

**The existence of another lower-cost nonthermal storage system would reverse this conclusion. However, as yet no definitive comparison of all storage devices has been performed.

Table 5.1 Utility Savings Versus Customer Payback Requirements[a]

Service Area[b]	Application	Storage Discharge Period (hrs	Annual Consumption (kWh)	Utility Savings (¢/kWh)	TES Increm'tl Cost ($)	Payback Req'd to Commercialize[c] 3-year $/yr	3-year ¢/kWh	5-year $/yr	5-year ¢/kWh
A	Hot Water	4	5,840	1.0	105	35	0.6	21	0.4
A	Hot Water	16	5,840	3.3	320	107	1.8	64	1.1
A	Space Htg.	8	28,000	5.1	2,840	946	3.4	568	2.0
B	Hot Water	4	5,840	2.0	105	35	0.6	21	0.4
B	Hot Water	16	5,840	3.3	320	107	1.8	64	1.1
B	Space Htg.	8	27,600	2.9	2,760	945	3.4	552	2.0
C	Hot Water	4	5,840	0.8	105	35	0.6	21	0.4
C	Hot Water	16	5,840	2.2	320	107	1.8	64	1.1
C	Air Cond.	8	2,500	14.6	1,095	365	14.6	219	8.8
D	Hot Water	4	5,840	1.9	105	35	0.6	21	0.4
D	Hot Water	16	5,840	3.1	320	107	1.8	64	1.1
D	Hot Water	8	6,500	14.6	1,325	442	6.9	265	4.1

[a]From Asbury, et al., *Assessment of Energy Storage Technologies and Systems, Phase I: Electric Storage Heating, Storage Air Conditioning, Storage Hot Water Heaters*, Argonne National Laboratory, ANL/ES-54 (Oct. 1976).

[b]Service areas A and B are winter peaking; C and D are summer peaking. Thus, there are no net savings for air conditioning TES for service areas A and B or for space heating TES for C and D.

[c]Simple payback; does not include cost of capital.

unit. More importantly, customers prefer convenience and might feel that the longer and much more frequent storage discharge will involve considerably more disruption of their preferred lifestyles.

Because interruptible service requires utility control, a monthly credit form of load-management rate is most suitable. This format is the most direct, economical method to inform the customer of the cost savings: direct, because it informs of the value of the interruptibility and economical because no added metering is required. Implementation of the rate is easy: insert a clause in the general rate stating that all customers allowing controlled interruption of their hot-water heaters for up to four hours receive an $X/month credit.

Storage hot water heating is suited to a load-management rate, but of the per-kilowatt-hour variety. This rate prices use at marginal cost, the cost of generating power off-peak plus an allowance for control and metering devices. The customer price would be at least 2¢/kWh less than a conventional rate with this scheme. Time-of-use rates could also lead to commercialization. However, since proposed off-peak periods in time-of-use rates are shorter than 16 hrs, and because there are potential increased costs to the distribution system (which is more extensively examined in Sec. 5.3.2), the load-management scheme yields greater benefits and is more efficient.

5.3 *SPACE HEATING*

Four rate types can lead to commercialization of space conditioning thermal storage: (1) demand charges, (2) time-of-use energy rates, (3) combined energy and demand time-of-use rates, and (4) load-management contract rates. Each rate has advantages and disadvantages; however, to maximize social welfare, a load-management contract rate should be adopted.

5.3.1 *Demand Charges*

Demand charges have several advantages. They use inexpensive metering devices, are readily understood, and are widely used for large customers. They can make thermal storage economical under present conditions for some commercial and industrial consumers. For many of these users, space conditioning is not the principal component of demand. Therefore, shifting this use from peak can reduce demand charges. However, demand charges suffer from two critical disadvantages -- in the residential market they work poorly, and, more important, they are inefficient, since they do not indicate the time elements of cost. Experience in Vermont indicates that the electric demand for certain high-use appliances is sufficiently great to cause residential electric peaks by themselves. This type of peaking has led to intense customer dissatisfaction. Demand charges do level customer demand, but not necessarily system demand. Thus, the effects of coincident demand are not transmitted to the customer by this rate format. The proper signal could be given by varying the demand charge by time of year and by time of day. However, this converts the rate to a time-of-use one.

5.3.2 Time-of-Use Rates (kWh)

Continuous time-of-use rates are inherently efficient, and although metering equipment appears to be expensive, such rates reflect quite well the cost of generation, transmission, and distribution to the customer. Practical problems preclude such rate structures. Instead, certain times of year and times of day are marked off in discrete blocks sufficiently in advance so that customers can make adequate response. Thus, the peak becomes the peak period, a determinable number of hours during which the probability of attaining peak load is roughly equivalent, and priced the same for all such hours. This pricing scheme seems to work well with two exceptions -- the needle peak and the pre- and post-peak-rate period peaks. The needle peak arises because the peak time is underpriced, while the potential-peak periods are overpriced in this scheme. Hence, particularly with summer-peaking utilities, the peak period will be of short duration compared to near-peak periods, thus the title, needle peak.

The pre- and post-peak-rate periods also occur because of time-block pricing. As Vermont data indicated, developing a peak in the present off-peak period is easy. For these customers Fig. 4.2 reveals that this peak was rather steep. This peak results from overpricing the near-off-peak-period times and underpricing the off-peak hour adjacent to the peak-rate period. One means of alleviating this problem is to stagger peak times. For example, customers in half the substation area would have a peak period beginning at 8:30 a.m., while the others would have one beginning at 9:00 a.m. Despite these disadvantages, the off-peak rate reductions with time-of-use rates appear adequate to commercialize long-term storage devices.

Numerous problems can arise at the utility when unconstrained time-of-day rates are offered for space heating. When thermal storage provides the entire load, there are five causes of concern.

1. Effect Upon the Distribution Grid

Time-of use rates being proposed all include, in effect, a credit for distribution, since there is a demand component to the distribution network. For example, WEPCO estimates that the demand-related marginal investment for general secondary service is \$250/kW.* Therefore, removing 1 kW from peak is worth the annualized value of \$250. However, for at least the last portion of the distribution system, that related to the customers' peak demand, this value is incorrect. Indeed, in many cases, more investment is required to handle the increased load when diurnal heating demand is met by TES. Figure 5.1 shows Green Mountain Power Company's estimate of increased capital costs for transformers, service, meters, and control resulting from thermal storage. There are systems in which TES does not incur added costs. However, these are, in effect, overdesigned for distribution due to high installation costs. But, in any case, TES customers are unduly favored by the way distribution is treated in determining time-of-use rates.

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*Schedule 6, pl. D-6630-ER-2.

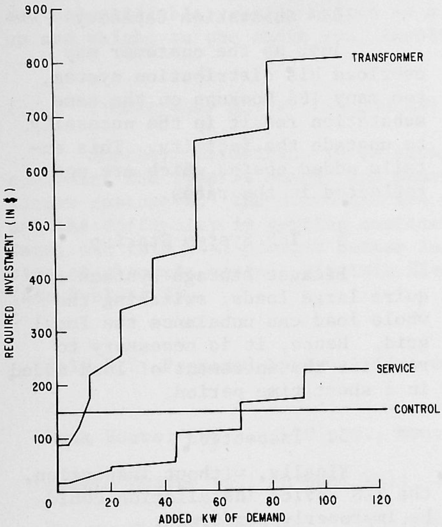

Fig. 5.1 Estimated Capital Cost of Increased Load on Distribution Net: Central Vermont Power Co.

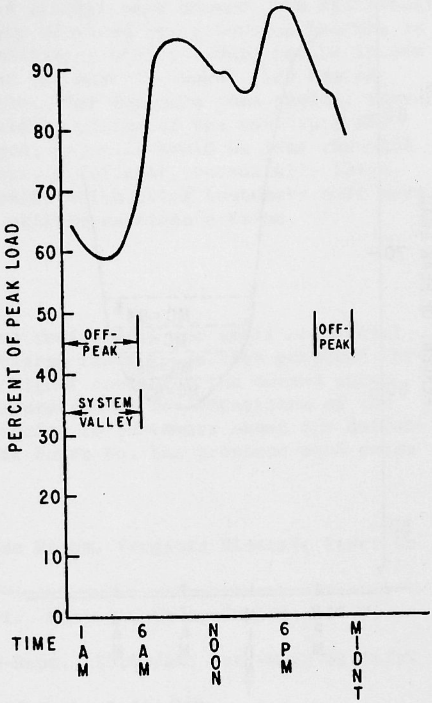

Fig. 5.2 Off-Peak Rate and System Load Valley, Green Mountain Power Co., 1975 Peak Day, Dec. 19, 1975.

2. Correspondence with System Valley

Time-of-use rates under off-peak periods do not entirely correspond to the system valley, as shown in Fig. 5.2. As can be seen, the peak period proposed, (14 hrs) is somewhat longer than the optimal storage time of 8 hrs as found in Table 5.1. This gives rise to two problems: (1) the threat of thermal storage adding to the system peak and (2) the relative price paid for energy being too high. As was shown earlier, there is a potential for large enough load shifting to place the system peak in the first hour of the off-peak period. Although staggering the peak period has been suggested, the installation of large amounts of storage units would undoubtedly cause a peak. This results in responsibility for capacity without paying for it. The response of changing the peak-period times solves this problem, but would lead to certain consumer dissatisfaction. The second problem arises because the marginal cost of energy increases with load. Most utilities practice economic dispatch, and hence the next increment of load added is usually more

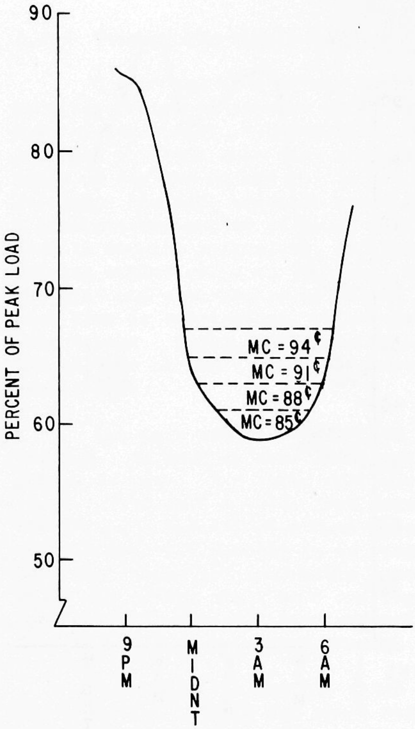

Fig. 5.3 Hypothetical Load Curve Showing Change in Marginal Cost (MC) as System's Diurnal Valley is Filled.

expensive than those already on line. Figure 5.3 depicts this. Because several high-use hours of the peak period are rolled into the price charged, it becomes somewhat higher than under an optimal loading arrangement.

3. Substation Capacity

Just as the customer may overload his distribution system, too many TES hookups on the same substation result in the necessity to upgrade the facility. This entails added costs, which are not reflected in the rates.

4. TES System Startup

Because storage systems require large loads, switching the whole load can unbalance the local grid. Hence, it is necessary to restrict the increment of load added in a short time period.

5. Inspection

Finally, without inspection, the TES device installation could be improperly performed.

The customer who makes an investment in TES must feel it is justified by the savings in operating costs. To the extent that future unfavorable rate changes are perceived, this attitude will discourage installation. A particularly damaging possibility would occur if the customer assumed a 10-hr off-peak period and then, in response to the off-peak needle peak, found this period shortened. Thus, uncertainty can act as a powerful deterrent. Since these rates are not device discrete, a customer who finds the cost for other service greater than before might not adopt TES, because these added costs reduce the effective return on investment to less than required. Thus, there are also two problems from the customer's side of the meter: (1) rate changes with leveling of load and (2) inability to divide customer-demand components.

In all likelihood, some customers will adopt a mixed-TES resistance-heating system. Because resistors are inexpensive relative to storage, for a fixed kilowatt-hour cost difference the customer's optimum system would contain both resistance and storage heat. Because resistors are not free, however, for the peak day(s) their system would use the entire thermal store as well as operate the entire resistance capacity for the peak period. Such a combination has all the problems of total storage systems, except that, because the addition of resistance reduces storage peak demand, the distribution effect is lessened. In addition the energy provided by resistance heaters is underpriced. Certainly in this system resistance heaters would not be in use at all times. In the severe winter period (at most 13 weeks), 120 hrs of peak-priced operation would seem reasonable. Yet for this same period, there are about 900 peak hours, and as each would be priced at the same rate and carry the same proportion of demand charges, payments would be less than 15% of the attendant capacity costs. Therefore, a definite, potentially large, and unjustifiable subsidy exists -- a subsidy which other customers must make up and which, in the short run, involves utility earnings erosion.

5.3.3 Time-of-Use Rates (kWh and kW)

Another possibility is to extend to residential and small commercial customers the type of energy and demand-charge time-of-use rate proposed for larger customers. The drawbacks are the higher costs for the demand meter and the difficulty in getting customer understanding and acceptance of the rate, but this does provide better information to customers about the derivation of electric costs. Virginia Electric Power Co. has proposed such rates (see Table 5.2).

Table 5.2 Proposed Optional Time-of-Use Rates, Virginia Electric Power Co.

Peak Hours: 10 a.m.-10 p.m., Mon.-Fri.	Customer Charge/Month: $9.85
Demand Charge (all on-peak kW): June-Sept., $5.09/kW; Oct.-May, $1.44/kW	
Energy Charge: On-Peak, 2.20¢/kWh; Off-Peak, 1.10¢/kWh	

Whether this rate type will gain public acceptance has to be resolved. If it does, however, then its effects upon pure storage heating systems would be similar to those of kilowatt-hour-only rates, except that the post-period peak could be exacerbated. For mixed systems, however, this is a far superior rate, since it better reflects the real costs of the resistance heat component. Thus, for the same utility, the mix would show both less resistance heat and a smaller subsidy from the mix.

5.3.4 Load-Management Contract Rates

Load-management contract rates, offering a low kilowatt-hour price, are superior for commercializing TES because they can be tailored to the effect of a unit upon the utility system. They can therefore overcome the disadvantages involved with time-of-use rates. These rates can be either formal or informal. They may require a separate signed contract or simply be a subsection of the standard rate. They may or may not involve utility control achieved by radio, ripple control, or some other technique. Uncontrolled systems, such as those using a time clock, are less expensive; however, their reliability is lower and they lack flexibility. The

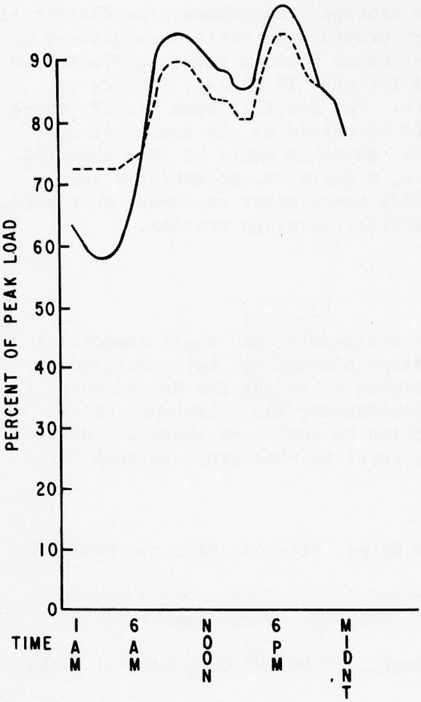

Fig. 5.4 Depiction of 5% Shifting in Demand from Peak Period to Optimal Location in System Valley, GMP Load Curve, December 19, 1975.

controlled systems need only be used when needed. The principal advantage of control is provision of the best possible fit of storage to system load. Figure 5.4 shows how this can be achieved by reducing load in the peak period by 5% of system peak and optimally redistributing it into the system valley. There is therefore a tradeoff between increased costs and benefits from control that each utility must evaluate to determine its feasibility.

A special rate for load management can solve the customer and utility problems cited earlier. The rate itself accounts for the added distribution costs of TES. Periods of thermal storing can be tailored to the utility system load with fixed hours; or even better, as has been shown, the storage load can be located optimally with control. The three questions of available capacity, increments of load addition, and inspection are all easily solved by clauses such as those in Green Mountain's Load Management Agreement, which states that:

> The Company reserves the rights to reject applications for new or additional service under this agreement at locations where insufficient capacity exists...Equipment served under the provisions of this agreement shall have control facilities which restrict load (kW) added to the system to increments not larger than 14 kW at intervals of not less than 15 seconds...The Company shall have the right to inspect equipment served under this agreement at all reasonable times.

Because load management contracts provide a discrete rate for storage, they solve the second customer storage problem, higher cost for other service with the time-of-use rates, while the ability to add capacity only in the valley ameliorates the uncertainty question. A formal contract with control could solve this problem, as placing load in the valley avoids the switch in off-peak hours, while the contract could have a clause stating that for X years the rate-making format for these customers will remain the same with only fuel adjustments and customer charges varied. After the initial time period, which reflects the requirements of customer payback, rate contracts could be placed on an annual basis, with rate based on current marginal cost of the customer's usage. This policy could be objected to on grounds that it treats similar customers differently. However, it merely indicates that, for system purposes, there is a real difference among customers based upon the time of hookup. The ability to guarantee stability is a second advantage over time-of-use rates, which should change as usage patterns change. It, in effect, is a temporary freeze of rates at that level of system cost encountered during the period (in years or half-years) of hookup to facilitate commercialization.

Everything that applies to pure TES systems is true for mixed systems, those with both storage and resistance heat, except that combining a contract and control adds the exciting possibility of truly optimizing this system. As the load curve in Fig. 5.4 shows, the peak period is relatively short; if hours at 95% of peak or more are considered the true peak period, then the midday dip becomes "nonpeak." Now assume the load for the home on the peak day is 360 kWh and due to the thermal mass of the house is evenly divided, that is, 15 kWh per hour, and that 20 kW of storage is optimal based on an 8-hr charge time. Thus, for the 16-hr discharge, 160 or 10 kWh/hr are available. The simple approach is to add 5 kW of resistance and to run this all day. However, since resistors are inexpensive compared to the electric system capacity, a formal contract would indicate this. The systems installed would have the thermal store provide all 15 kWh during the true peak and less than 10 kWh during the nonpeak. Thus not 5 kW of resistors, but perhaps 10 kW, would be installed and used in conjunction with the store to provide 15 kWh for the nonpeak hours in the peak period. This provides the full benefits of reducing system peak available via TES while simultaneously requiring minimum customer investment.

Because load-management contract rates are best for maximizing social welfare, especially when combined with utility control, they are clearly the rate type best suited for space-heating thermal storage. The rate level itself would be set at the cost of off-peak service for storage, while resistance heat, if any, would be charged all costs incurred. The reduction over conventional rates would be at least 2¢/kWh, after increased utility costs of control and meeting are allowed.

5.4 AIR CONDITIONING

Because of the massive price discount required by current storage air conditioning technology, only a load-management rate is a feasible commercialization strategy.

Load-management rates, in fact, may not always be feasible. As can be deduced from Table 5.3, there are many in which the price per kilowatt-hour would have to be negative to commercialize TES.* This would not be efficient.

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*At present, most utility rates are less than 5¢/kWh. Thus, except for service area D with five-year payback, a negative rate would be required for commercialization.

Table 5.3 Utility Savings Versus Customer Payback Requirements for Air Conditioning[a]

Service Area	Annual Consumption kWh	Utility Savings $	Utility Savings ¢/kWh	TES Incrm'tl Cost $	Payback Req'd to Commercialize[b] 3 year $/yr	3 year ¢/kWh	5 year $/yr	5 year ¢/kWh
C	2500	365	14.6	1095	365	14.6	219	8.8
D	6500	949	14.6	1325	442	6.9	265	4.1

[a] See Asbury, et al.

[b] Simple payback does not include cost of capital.

Under such a rate, customers would be *paid* to waste off-peak electricity. Yet such waste would not increase savings from the customer hook-up, as implied by the rate. Unfortunately, paying a monthly credit also has serious drawbacks. Done properly, the credit amounts to that portion of benefits not covered by the savings due to setting off-peak price equal to operating cost. This, in the systems examined, ranges from about $240 to $750 per year.* Such large credits do not seem politically feasible, as this service cannot be extended to all customers. In all likelihood it cannot even be extended to all air-conditioning customers because of electricity distributional impacts. Therefore, this situation would not be acceptable to other customers or to PUCs. Even a credit that met only the required customer payback could be suspect. Assuming a three-year payback, this credit would be more than $200. Although far fewer customers would now receive net payments from the utility, this credit is still large enough to warrant regulatory concern. Offering a credit allowing a five-year payback might succeed, since in cases such as service area D the credit would be small, less than $70 per year. However, this might not provide sufficient customer incentive.

The alternative is for the utility to own the device. This avoids the political complaints attendant to large credits. It also should overcome the problem of customer incentive, since no customer investment would be required. Instead, for allowing the utility to own, install, maintain, and control a device on his premises, the customer would be given an off-peak rate on usage. There are two other advantages to this approach; it may lower unit costs, and investment would go directly into the utility rate base. By the utility owning the device, it can purchase directly from the manufacturer, avoiding the distribution network and its attendant costs. This yields a lower effective price than if each customer were to purchase a system. Because many utilities cannot include capacity construction work in progress in the rate base, storage would be attractive. The time between ordering the unit and its installation would be considerably less than for gas turbines, which involve considerably less delay than other current generating devices.

*The off-peak savings over a standard rate is about 3¢/kWh. The cost of control accounts for the remainder of the difference between total savings and how large a credit could be offered.

The problems of utility ownership, however, outweigh the advantages. There are several legal questions. Because telephones are owned and maintained by utilities but operated by customers, ownership itself should be feasible. However, there are potential questions involving access and transfer of building ownership. There is the tremendous nuisance value involved in owning hundreds or thousands of widely dispersed devices on customer premises. At a minimum, this would require greater customer-relations efforts and expense. But the critical problem is that the savings from storage air conditioning result almost exclusively from reducing peak demand. Therefore, if customers who would not otherwise use air conditioning are induced to do so, the benefits of storage could be eliminated. This possibility is likely to arise with utility ownership because the customer does not have to make any investment.

Therefore, the load management rate adopted should offer off-peak power at cost plus a credit just sufficient to induce customers to choose storage over conventional air conditioning. Should the technology become inexpensive enough, the difficult task of determining and providing this credit should be discontinued, and only an off-peak price discount provided.

6 NONRATE BARRIERS AND RECOMMENDATIONS

6.1 EQUIPMENT

Translating the TES concept into reality requires reliable equipment, equipment that has been tested under the severest conditions to be met in the field. Those devices that are introduced before such reliability has been demonstrated often have unacceptable failure levels. Premature introduction thus results in a bad reputation hindering reintroduction of the device once the problems are resolved. Fortunately, for both space heating and hot-water storage, tested, proven systems are available. Two of the principal storage system producers in Europe, AEG-Telefunken and Siemens, are selling their space-heating units in the U.S. These units have been proven effective in over a decade of service, and any modifications required for the American market are currently being determined by experience from the first handful of customers. In addition, Megatherm is offering a hydronic storage unit, while Hooker Chemical and Comstock and Wescott are well along in developing Thermbank, a sodium hydroxide heat-of-fusion device. Storage hot-water units have been developed and are being offered by Patterson-Kelley, Inc., and others. A larger tank might be desirable for interruptible service. However, Buckeye Power's experience in installing controls on existing units indicates the larger tank is unnecessary. Thus the units for commercializing space heating and hot-water-heating storage are available. Hence implementation can start.

This is not the case for air conditioning. There is no commercially available storage device. Although several promising devices are under development, commercialization for residential and small commercial customers must await development of equipment.

6.2 INFORMATION

Two areas in which information dissemination is crucial to TES are (1) understanding of rates and (2) knowledge of TES. Another important area is the life-cycle-cost question. A significant difference in the difficulty of this task is likely for commercial establishments as opposed to residences.

In general, commercial establishments are larger consumers, with more at stake, and those already paying demand charges are accustomed to more complicated rates. They are more sensitized to the demand component of cost, while their own business experience undoubtedly makes education easier. Thus understanding rates is unlikely to be a major problem. Spreading the word on TES should be neither arduous nor expensive, since these customers can be reached initially via ads and articles in industry journals in addition to utility advertisements. Life-cycle cost is not a major obstacle because the loans that firms receive are based on expected profit as much as on assets.

On the other hand, transmitting effective information to residential customers is quite difficult. A major reason for this difficulty is that their lower electricity expenses provide less incentive to devote time to understanding rates. Experience in Britain has shown that, for customers not partaking in experiments, drastic action was required to promote understanding.

"A complete interruption of supply, when overuse was attempted, was a much better educator of the consumers than all the abstract advice previously offered."*

Utilities must make extensive efforts to inform customers of TES since so many residences are potentially involved. There will be a synergistic effect in that knowledge of rates will impel some customers to look for devices to take advantage of these rates, while knowing of TES will make understanding the rate more worthwhile.

At present, the value of energy savings derived by installing insulation, thermal storage, or any other capital-intensive energy-saving device is not capitalized into the value of the house. Thus the entire investment must be written off much faster than under an actual equipment depreciation scheme. Suppose, for example, that the customer had a 5-year payback period, the device lasted 20 years, and the effective interest rate was 10%. Then the burden rate, the rate of return that pays both the investment and interest in that given period, is about 26% with immediate write off, 15% with straight-line depreciation, and 19% with accelerated depreciation (10 years). Clearly, the required return will be considerably lower and hence expected demand for TES devices much larger if a life-cycle cost-appraisal scheme is adopted.

6.3 INSTITUTIONAL SUPPORT

There are two crucial institutional barriers: those pertaining to regulations, codes, etc.; and support of the utility involved.

Unless, and until, local and state building and safety codes are met, units cannot be installed. To date this has not been a problem and has resulted in only negligible delays. However, approval by Underwriters Laboratories is required in many markets, such as buildings sponsored by the federal government. This requirement entails costly and time-consuming testing. At present the German units have not been approved, but are in the testing process. Given the observable characteristics of storage units, this is merely a delay, as the code and standards are not expected to be prohibitory.

The European experience revealed the importance of utility support. Where the utilities made a commitment to storage, storage was introduced first, fastest, and for the greatest proportion of the system. There is no reason to suppose things will be different in North America. Thus the development of utility support is crucial. In one sense this is solved with rates, since, especially if load-management contract rates have been adopted, the utility makes a commitment to storage. But even this commitment may not represent the full-scale support involved in a customer-information program. Thus it is important to develop the support of the entire corporate utility organization; not to do so will certainly impede TES installation.

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*N. Briggs, *Comparison of Cash Collection Methods for Underfloor Heating Installations in Multi-Story Flats*, 2nd International Conf. on Metering Applications and Tariffs for Electricity Supply, IEE, p. 46 (Sept. 1972).

Other groups whose support is helpful, though not as crucial, are workmen (i.e., the unions), architectural and designing professions, and regulatory commissions. Clearly, unions have the power to block a new technology, though this is unlikely, while regulatory commissions do mandate utility service. However, these seem to be minor barriers.

6.4 POLICY PRESCRIPTIONS

These policy prescriptions adopt the global-efficiency, or social-welfare, viewpoint, which has formed the focus of this work. The recommendations are made as if there were a national agency.

The introduction of TES is not, at present, a marketing problem, but involves a question of rates. Once justifiable rates for TES have been established, then marketing will become the prime consideration. The types of rates best suited to TES, both for diurnal storage and for interruptions, have already been presented. Two important steps need to be taken in implementing actual rates based upon these guidelines: (1) dissemination of information about these rates and why they are suitable to all parties involved in the setting of electric rates, and (2) the preparation of testimony, both generic and utility-specific, on TES and rates before PUCs. This could be performed by either government energy agencies, EPRI, or a combination. These recommendations extend only to the generalized conditions necessary for TES to succeed. The particulars, must, of necessity, be developed by the respective utilities in concert with their PUCs.

An important step in both information dissemination and resolution of legal problems is testimony before PUCs and other regulatory and judicial bodies. Although utility support and understanding of TES are crucial, so are regulatory proceedings to provide rates and set allowable service standards, which, however, will not happen without the presentation, in formal hearings, of the issues involved. For, until these issues are raised and resolved in the regulatory and judicial realms, introduction of TES is likely to be both less than warranted and based upon incorrect rates, making it more costly, socially, than should be necessary.

Although rates must be established and rate-related issues resolved as preconditions, it is also crucial for the utility to actively support TES. European experience indicates a direct relationship between utility support and TES installation, particularly during the introductory phase, and this will undoubtedly be true of the U.S.* Developing active support goes beyond information on TES to explaining its advantages to the utility in maintaining profits and in providing an exciting challenge to personnel, the type of

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*"... the application and the distribution of electric storage space heating appeared to depend entirely on whether, and to what extent, the relevant utility promoted the use of these heaters either by tariff measures or by advice given to customers." From H. Masukowitz and W. Saywer, *German Experience with Electric Storage Space Heating*, Transactions of the Canadian Sectional Meeting, World Power Conf., *6*:2915-2976, Montreal (1958). See also J.G. Asbury and A. Kovaulis, *Electric Storage Heating: The Experience in England and Wales and in the Federal Republic of Germany*, Argonne National Laboratory Report ANL/ES-50 (April 1976).

challenge essential to a healthy company. "The employee does not only have a need for higher pay; he also has a need for challenge, recognition, and personal growth."* There are many such challenges involved that affect personnel in rates, marketing, sales, production planning, and dispatching. Of course, the most effective means to convey such information is by word of mouth. Nothing succeeds more than a knowledge of a program that has been conducted successfully by an industrial colleague and is clearly applicable to one's own system. But reaching this stage involves some experience with TES. Hence, it is clearly important to set up seminars and conferences on TES; participate when possible in rate and TES programs conducted both by individual utilities and by EPRI; and participate with utilities in establishing rates, rules of service, and TES experiments whenever such cooperation is sought. Once the initial steps are taken, then, if successful, TES will spread on its own impetus, although the maintenance of a small body of experts who have knowledge of the issues, have experience with introduction of TES by innovative utilities, and continue research on problem areas would be helpful.

Informing consumers of TES is the last key link in commercialization. Once utility support has been developed, the sales and marketing personnel can be relied upon to effectively inform customers. In the interim, before such support is developed, this role will be filled by the nascent thermal industry. Thus, this important area of activity is best left to the private sector.

The preceding analysis indicates that, to attain maximum benefits from TES, governmental agencies, either directly or via agents, and/or EPRI, should take the following measures: (1) provide expertise on proper rates for TES devices, (2) work with utilities to develop their support of TES, (3) conduct research and development on storage air conditioning, and (4) promote the introduction of the life-cycle-cost concept into the housing market.

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*A. Low, *Zen and Creative Management*, Anchor Press, Garden City, New York, p. 13 (1976).

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APPENDIX I: DESCRIPTION OF A COMMERCIALLY AVAILABLE STORAGE HEATER

Manufactured by AEG - Telefunken, 85 Nurmberg 2, Postfach 180, West Germany.

System Description. Heat-transfer medium: Air. Resistance heating elements: NiCr 80/20. Available in ratings of 2, 3, 5 and 6 kW.

The TES is charged with the electric resistance heater over an eight-hour time frame during the off-peak electric power period. Energy use is monitored with a two-rate meter. Discharging occurs as heat is required and is thermostatically controlled with an electric fan for circulating the room air past the heated stores.

System Application. Individual room heating: dispersed location

Storage Medium. Magnesite bricks

Storage Capacity. 68,500 Btu for 2 kW to 205,500 Btu for 6 kW. One may assume the other sizes to be proportional, although not so stated by the manufacturer.

Performance. Core temperature = 600°C maximum. Unit surface temperature = 65°C maximum. Charging rate (4 kW unit): 34,400 kcal (137,000 Btu) in 8 hrs. Other rates may be assumed to be proportional to unit capacity, although not so stated by the manufacturer. Discharge: thermostatically controlled, forced-air circulation (electric fan); room temperature maintained within ±0.5°C. Maximum fan noise level: 35 dB.

Capital Cost. Approximately 80-100 $/kW, effective as of Jan. 1, 1976

APPENDIX II: A BRIEF REVIEW OF PEAK-LOAD PRICING THEORY

Pricing With Shifting Peaks Where Demand Is Independent

The analysis here follows that of Williamson.[a] Assume that:

1. Costs per cycle are B for capacity and b for operation per period.
2. There are two equal-length periods of fixed demands, with demand in period 1 exceeding that in period 2.
3. The good produced is not storable.

A question arises as to how pricing should proceed when capacity is insufficient to meet demand in period 2 because all capacity costs were placed upon period 1. The intuitive answer is that some portion of capacity costs should be met by the period 2 consumer. The question is, how much?

Figure II.1 depicts the method to determine the addition of demand when it is in excess of b, operating costs. As can be seen, when price is at b, demand in period 2 is at G, implying the need for Q* of capacity; however, only Q_2 could be provided if all capital costs were placed upon period 1. This is considerably less than Q*; hence the effective peak demand is shifted to period 2.

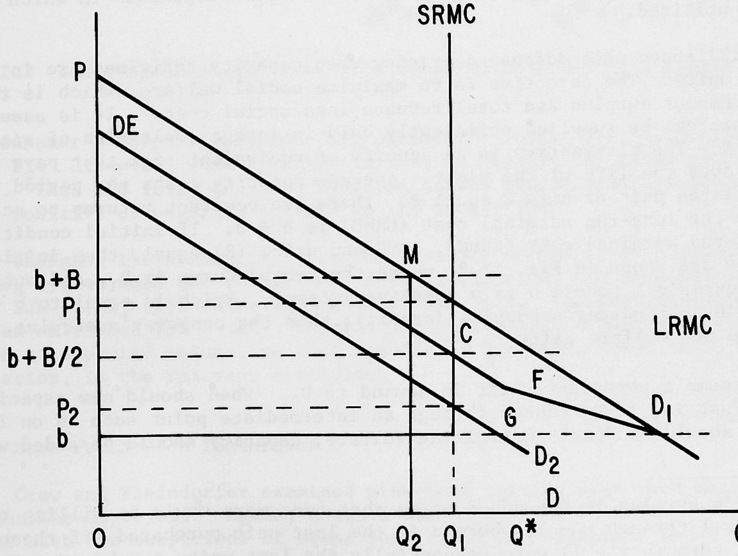

Fig. II.1 Determination of Prices for Shifting Peaks

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[a] Williamson, O.E., *Peak Load Pricing and Optimal Capacity*, American Economic Review, *61*:810-827 (Sept. 1966).

Combining the two demand curves to form DE leads to determination of the proper market clearing prices. This combination involves (1) taking the vertical difference between the periodic load curves D and D and short-run marginal costs (SRMC); (2) when SRMC equals b, multiplying this difference by the fraction (W_i) of the cycle for the period load (in this case 1/2); and (3) adding the weighted curve vertically. The kink at F results simply because beyond that point the demand price in period 2 (off-peak) is below SRMC, b. Note that SRMC equals b until it becomes infinite where the limit of capacity is reached.

At C, where LRMC equals effective combined demand, demand is equal to Q_1, and the available supply in periods 1 and 2 and prices P_1 and P_2 together equal B + 2b, total system cost.

This solution has two intriguing features. First, it demonstrates that off-peak demand (period 2) contributes to some peak capacity if, when priced at b, it exceeds the capacity that would be installed if all capacity costs are placed upon the peak. Thus Q_1 exceeds Q_2, which would be capacity, without shifting peaks. Second, for a multiperiod system, the pricing rule is: off-peak P_i = b, and with I the subset of periods when capacity is fully utilized,

$$\sum_{i=1}^{n} (P_i - B) W_i = B,$$

where W_i is the proportion of the entire period for subperiods in which capacity is fully utilized.

Williamson also addressed pricing when capacity additions are in discrete units. The objective is to maximize social welfare, which is the sum of consumer surplus and total revenue less social cost.[a] It is assumed that plants can be supplied efficiently only in integer multiples of size E and cost T. The alternative is an annuity of equivalent risk that pays an amount γ over the life of the plant. Average capacity costs per period of a fully utilized unit of size E equal B. There are constant returns to scale, and hence the long-run marginal cost (LRMC) is b + B. If initial conditions are short-run marginal cost (SRMC), LRMC and price (P) equal, then initial conditions are shown in Fig. II.2, where the demand curve is D_1, and output is Q*. Q* equals n E, where n is a positive integer. Price is equal to b + B, so there is no producer's surplus (profit); thus the consumer's surplus, UNG, equals the net welfare gain.

Assume a permanent shift in demand to D_2. When should new capacity be added? That is, if D_2 passes through an intermediate point such as on line NK, what should be done? Maximizing welfare, capacity should be added when

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[a] Consumer's surplus is the added price that consumers would be willing to pay for units 1 through x - 1, where x is the last unit purchased, if these units (1 through x - 1) were sequentially the last units purchased. That is, since unit 1 of a good is generally more valuable to consumers than unit 100, they would be willing to pay more for it. However, if 100 units were available, the price per unit (without monopolistic discrimination) equals the value to the consumer of unit 100, and hence there is a surplus.

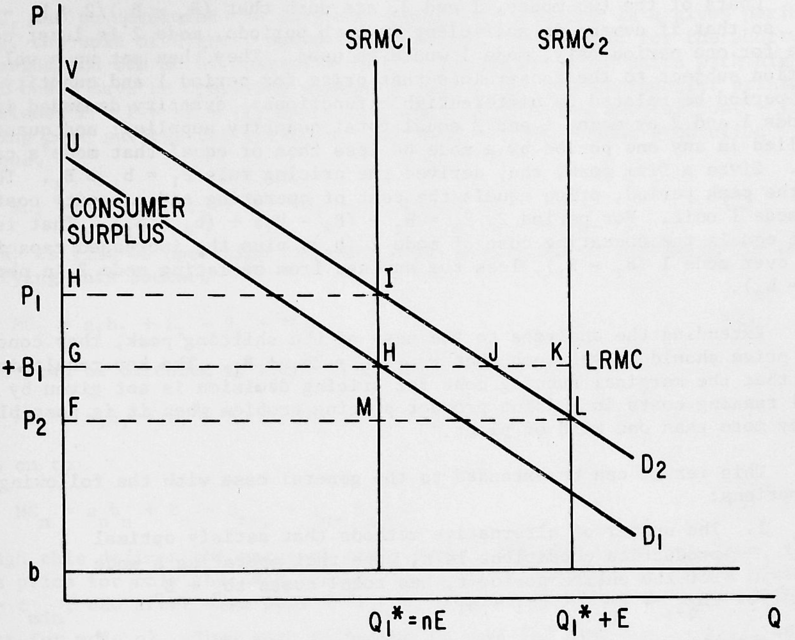

Fig. II.2 Determination of Prices When Capacity Is Added in Discrete Amounts

IJN, consumer's surplus, exceeds JKL, producer's loss. The appropriate price is now P_2. Likewise, when JKL exceeds IJN, no capacity is added and price is now P_1. Thus the fully adjusted long-run static equilibrium can be one with either positive or negative profits to the enterprise.

Changing the assumption of a once-for-all change to a constantly changing system does not change this result, since, if new capacity is added before IJN $\geq$ JKL, then there is a net welfare loss. New capacity should still be added only when IJN $\geq$ JKL. Introducing uncertainty simply involves conversion to expected values, so that now E(IJN) $\geq$ E(JKL), where E( ), denoting expectation, is the relevant criterion.

Two or More Production Techniques

Crew and Kleindorfer examined peak-load pricing when more than one kind of plant was employed.[a] Again, using a social-welfare function, they set up a model with two subperiods of equal length and two different modes of produc-

[a]Crew, M.A., and P.R. Kleindorfer, *Marshall and Turvey on Peak Load or Joint Product Pricing*, Political Economy, pp. 1369-77 (1971).

tion. Costs of the two modes, 1 and 2, are such that $(B_2 - B_1)/2 < b_1 - b_2 < B_2 - B_1$, so that if demand is sufficient in both periods, mode 2 is least costly, while for one period only, mode 1 would be used. They then set up a welfare function subject to the constraints that price for period 1 and quantity for that period be related by differentiable functions: quantity demanded in periods 1 and 2 by modes 1 and 2 equal total quantity supplied; and quantity supplied in any one period by a mode be less than or equal that mode's capacity. Given a firm peak, they derived the pricing rule $P_1 = b_1 + B_1$. That is, for the peak period, price equals the cost of operating and capacity costs of the mode 1 unit. For period 2, $P_2 = b_2 + (B_2 - B_1) + (b_2 - b_1)$. That is, price equals the operating cost of mode 2 (b_2), plus the increased capacity cost over mode 1 $(B_2 - B_1)$, less the savings from operating mode 2 in period 1 $(b_1 - b_2)$.

Extending the analyses to the case of the shifting peak, they conclude that price should be set such that $P_1 + P_2 = 2b_1 + B_1$. The key result is "... that the marginal running cost for pricing decision is not given by marginal running costs in a joint product pricing problem when it is possible to employ more than one kind of plant."[a]

This result can be extended to the general case with the following assumptions:

1. The number of alternative methods that satisfy optimal production conditions is n, such that operating a mode for the entire period t, has total costs $tb_n + B_n < tB_{n-1} + B_{n-1} < tb_1 + B_1$

2. All methods of production are optimal for some time periods; thus,

$$\frac{B_n - B_{n-1}}{t} < b_{n-1} - b_n < B_n - B_{n-1};$$

$$\frac{B_{n-1} - B_{n-2}}{t} < b_{n-2} - b_{n-1} < B_{n-1} - B_{n-2};$$

.

.

.

$$\frac{B_2 - B_1}{t} < b_1 - b_2 < B_2 - B_1.$$

Given these assumptions, a rigorous analysis based upon the work of Crew and Kleindorfer could be applied. However, we shall use an alternative method, which, while not as elegant, yields the same result. This is to set

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[a]Kleindorfer, p. 1376.

$P_i = MC_i$ and to determine the marginal costs for operating in a given period. Clearly, the unit of highest operating cost will be operated for the shortest time period and the MC of operation is $b_1 + B_1$, while other units with higher capital costs save on operating expenses. Thus the Crew-Kleindorfer pricing conclusions, P = P = MC = (1) operating costs + (2) added capital cost + (3) operating cost savings are extended, such that for the second production technique,

$$MC_2 = (a_2 - a_1)b_2 + B_2 - B_1 + a_1(b_2 - b_1), \tag{1}$$

where a_1 is time of operation for unit 1 and a_2 is time of operation for unit 2. Simplifying this becomes

$$MC_2 = a_2 b_2 + B_2 - B_1 - b_1 a_1, \tag{2}$$

and this can be extended to subsequent technologies so that

$$MC_3 = a_3 b_3 + B_3 - B_2 - a_2 b_2$$

and so on to

$$MC_n = a_n b_n + B_n - B_{n-1} - a_{n-1} b_{n-1}. \tag{3}$$

Although this defines the marginal costs associated with each technique, it yields price for only the peak period. Each technique must be used a minimum time = t_{min}, and after some period (t_{max}), another technique is more efficient (except for mode n). Then each technique is used for time $t_{max} - t_{min}$, and the added costs of operation from such a technique, which result from its advantage for the given range of output, yield a portion unit time (hourly) MC of the form

$$MC_{sub\ 2} = \frac{a_2 b_2 + B_2 - B_1 - a_1 b_1}{a_2 - a_1} \tag{4}$$

and so on to

$$MC_{sub\ n} = \frac{a_n b_n + B_n - B_{n-1} - a_{n-1} b_{n-1}}{a_n - a_{n-1}}. \tag{5}$$

This marginal cost should be set equal to price. This is equivalent to the total marginal cost of operating a mode divided by the time that that mode is the highest operating cost mode in use. In an optimal system the prices are equal to operating cost for each unit type, except the peak unit whose price is the operating cost plus the cost of capital divided by hours in the peak unit operating period.

Peak Load Pricing and Rate Criteria for an Optimal System

In an optimally planned system, when prices are set equal to the marginal running cost at any given hour plus the capital cost of meeting one extra kilowatt of peak demand, they will meet revenue requirements and be fair. Let the symbols in Table II.1 be used in a system with three available technologies.

Table II.1 System Characteristics

Plant Type	Annual Capital Cost ($/kW)	Operating Cost ($1/kWh)	Operating Time (hr/yr)	Capacity (kW)
Peaking	X	x	a	A
Intermediate	Y	y	a + b	B
Base	Z	z	a + b + c	C

Table II.2 System Costs

Unit Type	Annual Capital Cost ($)	Hours in Use	kWh Generated	Operating Cost/kWh	Total Running Cost
Peak	AX	a	Aa	X	Aax
Intermediate	BY	B(a + b)	B(a + b)	y	B(a + b) y
Base	CZ	(a + b + c)	C(a + b + c)	Z	C(a + b + c) z
	Σ Capital				Σ Running

Table II.3 Revenues

Period in Which Marginal Unit Is:	Capacity in Use	Output	Price	Revenues
Peak	A + B + C	(A + B + C)a	x + X/a	(A + B + C)a(x + X/a)
Intermediate	A + B	(B + C)b	y	(B + C)by
Base	C	Cc	z	CcZ
				Σ Revenues

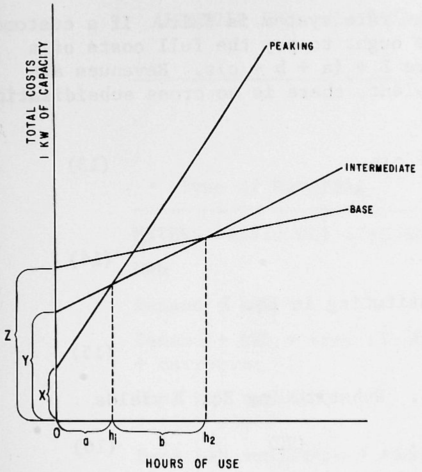

Fig. II.3 Unit Costs Over Time

When x, y, z, X, Y, and Z are given, for the optimally planned system, prices should be set at: peak hours (x + X/a) \$/kWh; intermediate hours y \$/kWh; base hours z \$/kWh. These prices result from the characteristics of an optimal system. For such a system, each plant type is used up to the time where the operating cost savings of the next plant type equal the increased capital costs associated with the switch. From Fig. II.3 then, peaking units are used until total costs X + ax are equal to Y + ay, at which point ax - ay = Y - X, and likewise intermediate units are used until Y + (a + b)y equals Z + (a + b)z.

Thus at h_1, production from peak-load units ceases, and at h_2, production from intermediate-load units ceases. When the system is optimized,

$$X + ax = Y + ay \tag{6}$$

and

$$Y + (a + b)y = Z + (a + b)z. \tag{7}$$

Total system cost is shown in Table II.2. And for this system, when priced as described earlier, revenues are listed in Table II.3. If a fair rate of return is to be achieved, then revenue equal costs, or Σ Revenues = Σ Running + Σ Capital, or

$$(A + B + C)a(x + X/a) + (B + C)by + Ccz = Aax + B(a + b)y$$
$$+ C(a + b + c)z + AX + BY + CZ. \tag{8}$$

This can be simplified to

$$BaX + CaX + BX + CX + Cby = Bay + Caz + Cbz + BY + CZ. \tag{9}$$

However, substituting Eq. 6 in Eq. 9 gives

$$Bay + Cay + BY + CY + Cby = Bay + Caz + Cbz + BY + CZ, \tag{10}$$

which, by cancellation, simplifies to

$$Cay + Cby + CY = Caz + Cbz + Cz, \tag{11}$$

and substituting Eq. 7 in Eq. 11 gives

$$Caz + Cbz + CZ = Caz + Cbz + CZ. \qquad \text{QED} \tag{12}$$

It can also be demonstrated that the rate system is fair. If a customer were to use 1 kW for (a + b + c) hours, he ought to pay the full costs of a base load unit. The costs in this case are $Z + (a + b + c)z$. Revenues are $a(X + x/a) + by + cz$. If these are equivalent, there is no cross subsidization and the rate is fair. Therefore,

$$a(x + X/a) + by + cz = Z + (a + b + c)z \tag{13}$$

or

$$ax + by + cz + X = Z + (a + b + c)z. \tag{14}$$

However from Eq. 6, $ax + X = by + Y$. Substituting in Eq. 7

$$ay + by + cz + Y = Z + (a + b + c)Z \tag{15}$$

and from Eq. 7, $ay + by + Y = (a + b)z + Z$. Substituting Eq. 7 yields

$$(a + b + c)z + Z = Z + (a + b + c)z. \qquad \text{QED} \tag{16}$$

It is just as easy to demonstrate that consumers who use only off-peak power should be charged only running costs and not be charged any capital costs, and that if consumers require all their power on-peak, then charging them peak unit capital costs covers the incremental cost to the system. Thus for an optimal system, peak-load pricing does meet the three criteria of efficiency, adequacy, and fairness.[a]

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[a]This section is based upon work performed by National Economic Research Associates (NERA).

APPENDIX III: COST OF METERING AND CONTROL DEVICES

Type of Metering	Approx. Inst'ld Cost ($)	Annual Est. O&M Expenses* ($)	Annual Revenue Req'd ($)
METERS PREVIOUSLY AVAILABLE:			
kWh	27	4.73	9.01
Demand + kWh	81	15.47	30.94
Demand + kWh + time clock + carryover	167	17.29	49.19
Dual kWh registers + time clock	84	17.29	33.33
Dual kWh registers + time clock + carryover	150	17.29	45.94
Dual kWh registers with second register demand activated	76	17.29	31.81
Magnetic tape + carryover	744	17.29	159.39
RECENT DEVELOPMENTS:			
ree kWh registers + time clock + seven day battery carryover	150	17.29	45.94
Dual kWh registers thermal demand + time clock + carryover	217	17.29	58.74
Automatic Meter Reading AMR	now: $1000/point future: $150/point		
AMR with load management	future: $300/point		
PRE-ASSEMBLED COMPONENTS:			
Dual kWh registers + internal time clock + carryover + thermal demand adapter	245	17.29	64.09
kWh + kW/kEh meter + time clock + carryover	320	17.29	78.41

*Virginia Electric Power Co., letter to Virginia State Corporation Council dated Nov. 1, 1975.

Metering Function to Be Performed	Possible Hardware Package	Approx. Cost of Hardware	Comments
			Metering could also be implemented using the proposed power-line automatic meter reading systems which eliminate the need for visual reading of the meters required in all other options. Estimated cost of hardware for metering: $100/customer.
On-Peak kWh and max kW, Off-Peak kWh	Watthour meter... + Watthour demand meter... + Time switch with 10-hr carryover...	$ 20 67 63 $150	A bulky package but manufacturers should easily be able to combine the last two items into one unit that would sell at a smaller cost.
	Watthour meter... + Watthour demand meter... + Ripple control	$ 20 67 100 $187	More costly, but a highly flexible system.
On-Peak kWh and max kW, Off-Peak kWh and max kW	Two watthour demand meters... + Time switch with 10-hr carryover...	$134 63 $197	
	Two watthour demand meters... + Ripple control...	$134 100 $234	

*A SAMPLE OF PRESENTLY AVAILABLE HARDWARE OPTIONS FOR METERING VARIOUS DOMESTIC RATES**

Metering Function to Be Performed	Possible Hardware Package	Approx. Cost of Hardware	Comments
Total kWh	Watthour meter...	$ 20	Metering could be implemented using Dacro's automatic "over-the-phone" meter reading system which is, however, probably too slow for implementation of time-of-day rates. Estimated cost: $55/customer for 100,000 units.
			Metering could also be implemented using the proposed power-line automatic meter reading systems which eliminate the need for visual reading of the meters required in all other options. Estimated cost of hardware for metering: $50/customer.
On-Peak kWh, Off-Peak kWh	Dual-register watthour meter with internal time switch...	$ 71	Timer not equipped with carryover and must thus be manually adjusted after power outages. Change of on-peak, off-peak hours also requires manual adjustment of timers.
	Dual-register watthour meter with solenoid operated registers....	$ 55	Power outage problem alleviated but system still inflexible.
	+ External time switch with 10-hour carryover	63	General Electric has a timer available with 30-hour carryover which sells for $86.
		$118	
	Dual register watthour meter with solenoid operated registers...	$ 55	More expensive than time switch option but ripple control can also be used to execute load management functions. System highly flexible -- can easily change on-peak, off-peak periods from weekday to weekend, from summer to winter, etc.
	+ Ripple control...	100	
		$155	

*Thomas Laaspere, Testimony Before Public Service Commission of New York, Case No. 26806, August 11, 1975.

Metering Function to Be Performed	Possible Hardware Package	Approx. Cost of Hardware	Comments
kWh consumption in "high," "medium," "low" rate periods	Watthour meter with internal time switch.. + Dual-register watt-hour meter with internal time switch..	$ 57 72 $129	
Any conceivable rate structure	Magnetic-cartridge recorder with internal time reference...	$367	The data-handling and processing costs will also be appreciable in this option.

APPENDIX IV: ELECTRIC LOAD MANAGEMENT AGREEMENT

Agreement between Green Mountain Power Corporation (the Company), and ______________________________ (the Customer), under which the Company will provide Electric Load Management service to be utilized at:

____
(Street or Road)

______________________ Vermont ______________
(Town or Village) (Zip)

____
(Account Number)

Line No. ____________________ Pole No. ____________________

for the following described equipment:

Description of Equipment ______________________________

____

____

____

Maximum Connected Load ____________ kW.

The Company agrees to provide Electric Load Management for the above described equipment at the above location under the following terms and conditions:

1. Service shall be a nominal 240 volts, single phase and shall be available only during such hours as the Company may direct, but not less than sixteen (16) hours during any twenty-four (24) hour period.
2. Service shall be supplied to electric equipment through a separate meter or meter register as the Company may specifically designate.
3. The Customer shall wire all equipment to a point designated by the Company, and provide all required relays and/or equipment control devices necessary to act upon such control signal as may be provided by the Company.
4. Equipment served under the provisions of this agreement shall have control facilities which restrict load (kW) added to the system to increments not larger than 14 kW at intervals of not less than 15 seconds.
5. Capacity of equipment connected to this service (name plate rating) shall not exceed one hundred (100) kilowatts.

6. This agreement shall be for an initial period of at least one year from the date of acceptance by the Company and thereafter from year to year, unless terminated as herein provided.
7. After the initial period either party may terminate this agreement effective November 1 of any year by giving the other party written notice on or before May 1 of the same year.
8. The customer may terminate this agreement because of the change of his or her permanent residence, by giving the Company 30 days written notice.
9. Subject to the approval of the Vermont Public Service Board, the provisions of this agreement may be modified by the Company, other than that contained in Paragraph 9, by giving the Customer notice in writing at least 90 days prior to the proposed change. The Customer shall have the option to terminate this agreement on the effective date of the change instituted by the Company by giving written notice to the Company on or before 60 days from the date of the Company's notice of the proposed change.
10. The energy charge per kWh shall be subject to the same fuel and/or energy cost adjustment as is applicable to kWh billings rendered under rates contained in the Company's regular schedule of electric rates.
11. Customer must make application to the Company prior to adding additional equipment (kW) which will receive service under this agreement.
12. The Company reserves the right to reject applications for new or additional service under this agreement at locations where insufficient capability exists.
13. The violation of any of the provisions of this agreement shall cause the Customer to lose the service, after proper notice, until such time as the violation is corrected.
14. Electric heating elements served under the provisions of this agreement shall not receive service under any of the Company's filed rates at any time during the term of this agreement. Auxiliary equipment such as thermostats, circulating fans and pumps will be served from regular service meter.

15. The Company shall have the right to inspect equipment served under this agreement at all reasonable times.
16. This agreement is made subject to the approval of the Vermont Public Service Board.
17. The monthly rate for service under this agreement is as follows:
    $0.35 per kW of equipment installed, plus
    $0.014 per kWh for the period as established in Paragraph 1.

	______________________________ (Customer)
______________________________ (Date)	______________________________ (Customer Signature)
______________________________ (Date)	______________________________ (Green Mountain Power Corporation)

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